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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769. (U39E)	Rulemaking 14-08-013 (Filed August 14, 2014)
And Related Matters.	A.15-07-002 A.15-07-003 A.15-07-006

(NOT CONSOLIDATED)

In the Matter of the Application of PacifiCorp (U901E) Setting Forth its Distribution Resource Plan Pursuant to Public Utilities Code Section 769.	A.15-07-005 (Filed July 1, 2015)
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PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E) DEMONSTRATION PROJECTS A AND B FINAL REPORTS

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Dated: December 27, 2016

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Pursuant to the May 2, 2016 *Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; And (2) Authorizing Demonstration Projects A And B* ("May ACR"),[1/] and the August 23, 2016 *Assigned Commissioner's Ruling Granting the Joint Motion of San Diego Gas & Electric Company, Southern California Edison Company, and Pacific Gas & Electric Company to Modify Specific Portions of the Assigned Commissioner's Ruling (1) Refining Integration*

1/ R.14-08-013, *Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; And (2) Authorizing Demonstration Projects A And B*, May 2, 2016, Appendix A at pp. 21, 37; R.14-08-013, *Assigned Commissioner's Ruling Granting the Joint Motion of San Diego Gas & Electric Company, Southern California Edison Company, and Pacific Gas & Electric Company to Modify Specific Portions of the Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B Southern California Edison Company*, August 23, 2016, Appendix A at pp. 21, 37.

Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B ("August ACR"), Pacific Gas and Electric Company respectfully submits its (1) Demonstration Project A Final Report and (2) Demonstration Project B Final Report, attached as Appendices A and B, respectively.

Pursuant to the May and August ACR[2/] and ALJ Mason's November 29, 2016 Email Ruling,[3/] both the ICA and LNBA Working Groups are required to submit a Final Report by January 31, 2017. The May ACR also directed that "Energy Division may provide further direction regarding the content and format of the report."[4/] Per the Joint Utilities' Joint Motion for Extension of Time granted by the ALJ's November 29, 2016 Email Ruling, PG&E has prepared and is filing its own Final Reports for Demos A and B at this time in order to provide the Working Groups with sufficient information and support for their Final Reports due January 31, 2017.

Respectfully submitted,

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2/ May ACR, at pp. 21, 37; August ACR, at pp. 21, 37.

3/ *E-Mail Ruling Granting San Diego Gas & Electric Company/Southern California Edison Company/Pacific Gas and Electric Company Joint Motion For One Month Extension To Submit Their Integration Capacity Analysis Work Group And Locational Net Benefits Analysis Working Group Final Reports*, ("November 29, 2016 Email Ruling"), November 29, 2016.

4/ *See* May ACR, at pp. 21, 37; August ACR, at pp. 21, 37.

APPENDIX A

PACIFIC GAS AND ELECTRIC COMPANY

INTEGRATION CAPACITY ANALYSIS

FOR DISTRIBUTION RESOURCE PLANNING

DEMONSTRATION PROJECT A – ENHANCED INTEGRATION CAPACITY ANALYSIS

FINAL REPORT

December 2016

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1 EXECUTIVE SUMMARY

The purpose of this report is to report details of Pacific Gas and Electric's (PG&E) Integration Capacity Analysis (ICA) methodology and results of the Distribution Resources Plan (DRP) proceeding Demonstration A project (Demo A). ICA is designed to evaluate the integration capacity (IC), a.k.a. hosting capacity, of an electric system that it has to integrate Distributed Energy Resources (DER).

PG&E is utilizing robust distribution datasets, new tools, and new approaches to create a more proactive look at DER and how it impacts the grid. ICA is a fundamental step towards ensuring a safe, reliable, and cost effective grid all while helping promote customer choice, optimal resource placement, and reducing greenhouse gas emissions.

Demo A serves as an exploration of new enhancements to ICA on a limited amount of distribution feeders. The main goals of Demo A are to drive more consistency between the utilities, explore multiple calculation techniques, and incorporate a set of requirements as prescribed by the California Public Utilities Commission (CPUC or Commission). With these requirements, it looks to explore feasibility of more spatial and temporal granularities along with expansion of the results to be hourly rather than one single minimum IC. The project also serves as a platform to test integration of the methodology into the tools in order to produce results for publication online in an efficient and repeatable manner. This is important for system wide scalability and inclusion into planning and interconnection processes. This report explores the technical details and underlying assumptions of this evolving methodology.

In general PG&E has learned that hourly results can be very useful in characterizing ICA in a way that fits with needs of the planning process going forward. However, this along with the increase of analysis and results to each node creates a massive amount of data that is more challenging to manage and publish than previous datasets. Properly understanding the complexities of DER behavior, system abnormal operations, and aggregator market participation will become more difficult with this level of locational and temporal granularity. Going forward PG&E needs to assess the IT requirements and optimization of implementation. It will also be important to assess with stakeholders the right amount of data that is actionable and feasible. This will vary based the final methodology ruled by commission due to the processing and publishing complexities.

As for the methodology itself, PG&E supports utilizing both calculation techniques, but only as appropriate and not to choose one or the other. It was discovered that each technique is better suited for specific applications of use. The streamlined techniques are better suited to more appropriately analyze large amounts of scenarios for planning purposes, while the iterative is better suited for analyzing circuit conditions for specific interconnection purposes.

The increase in computation has resulted in a massive amount of simulation that must be supported by complex IT systems and cloud computing. While the enhanced IT infrastructure utilized in the demo did help, PG&E still saw major complexities in dealing with the data. This was especially true with the iterative technique in which the nature of the technique required a significantly more amount of simulations and more complexity that in some cases resulted in non-convergent power flows. PG&E recommends that any use of the iterative technique be limited to less hours and scenarios as the computational burden and complexity of the analysis is not suited for the broad scenarios required for planning. The streamlined technique allowed for much better performance and certainty for results across broad ranging hours and scenarios. It is recommended that the streamlined technique be the main technique utilized for the planning use case and that iterative have a more focused use within the interconnection study process.

PG&E attempted to utilize development circuit models from the new GIS system in order to comply with the CPUC' s ruling item to analyze substation level power flows. Unfortunately the attempt resulted in poor performance and still had bugs in the model due to these new models not being production ready. PG&E attempted to resolve, but final results utilize the older GIS models which are currently being used in a production environment. The final results still analyze substation interconnection through layered abstraction to ensure the main substation components are still considered. This delay along with complexities of iterative simulations limited the ability to obtain as complete a result set for iterative as streamlined. Valuable learnings were still obtained and can be seen in this report. It is expected that in cooperation with the software vendors that more development can help optimize and enhance going forward. This report along with stakeholder engagement and industry collaboration will help ensure that the ICA methodology is refined to properly meet the needs for distribution resource planning in California.

2 BACKGROUND AND OBJECTIVES

2.a DRP and Demonstration A Overview

As described in the original DRP Guidance document[1], the purpose of Demonstration A (Demo A) is to demonstrate a fully dynamic analysis based on the Integration Capacity Analysis (ICA) methodologies developed for the IOUs' 2015 DRP filings. To this end, an Assigned Commissioner's Ruling (ACR)[2] was issued on May 2, 2016 instructing the IOUs to implement a modified ICA methodology in Demo A based on methodology proposed in the DRP filings. On August 23, 2016, the Commission issued an Assigned Commissioner's Ruling[3] (August ACR) granting the joint motion of IOUs to modify specific portions of the May ACR. The ICA methodology used in the Demo A project strived to meet the modified baseline methodology as specified in the ACRs. This section will explain how these requirements are met. Pursuant to the ACRs, the baseline methodology shall have the following specifications:

Baseline Methodology Steps

1. Establish distribution system level of granularity
2. Model and Extract Power System Data
3. Evaluate Power System Criterion to determine DER capacity

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[1] Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 - Distribution Resources Planning, February 6, 2015.

[2] Assigned Commissioner's Ruling (1) Refining Integration Capacity And Locational Net Benefit Analysis Methodologies And Requirements; and (2) Authorizing Demonstration Projects A and B, May 2, 2016.

[3] Assigned Commissioner's Ruling Granting the Joint Motion of San Diego Gas & Electric Company, Southern California Edison Company, and Pacific Gas & Electric Company to Modify Specific Portions of the Assigned Commissioner's Ruling (1) Refining Integration Capacity And Locational Net Benefit Analysis Methodologies And Requirements; and (2) Authorizing Demonstration Projects A and B, August 23, 2016.

4. Calculate ICA results and display on online map

How each of these steps are incorporated into the Demo A project is described below.

Baseline Methodology Steps

1. **Establish distribution system level of granularity**
    - PG&E' s initial filing complied with guidance to perform analysis and achieve results granular down to the line section and node level. Nodes were isolated for computational efficiency, but Demo A explores analysis at all nodes in the system.

2. **Model and Extract Power System Data**
    - A Power Flow Analysis Tool is utilized for geospatial circuit models with all necessary components to analyze all the nodes on the primary distribution system.
    - A Load Forecasting Analysis Tool is utilized for forecasting and modeling of load profiles across the system to the proper hourly granularity as required by the May 2nd Ruling.

3. **Evaluate Power System Criterion to determine DER capacity**
    - Four major criteria of Thermal, Protection, Power Quality/Voltage, and Safety/Reliability are considered and analyzed in the analysis. The demo project includes components in Table 2-4 of PG&E DRP were practicable at this time.

4. **Calculate ICA results and display on online map**

- Results across the different layers of the system (i.e. line section, feeder, substation transformer) are extracted from the analysis and published to the online RAM map. Knowing results of different layers can help inform smaller scale retail developers as well as larger scale wholesale developers.

2.b CPUC Requirements

The ACRs include the nine functional requirements described below.

1. Quantify the capability of the distribution system to host DER
2. Common methodology across all IOUs
3. Analyze different types of DERs
4. Line section or nodal level on the primary distribution system
5. Thermal ratings, protection limits, power quality (including voltage), and safety standards
6. Publish the results via online maps
7. Use time series models
8. Avoid heuristic approaches, where possible
9. Demonstrate dynamic ICA using two DER scenarios including no backflow and maximum DER capacity irrespective of power flow direction

Modifications to Include in the Baseline Methodology

1. **Qualify the Capability of the Distribution system to Host DER**

a. Electric distribution feeders (a.k.a. Circuits) were modeled in the power flow software with the individual capacitor bank devices that contribute reactive power to the circuit.
b. Effects of load modifying resources (i.e. Energy Efficiency and Demand Response) can be explored in two ways. The first method for reflecting the effect of potential load modifying resources for ICA is to examine the "net" loading effect of load modifying resources which will change the loading conditions to which ICA is calculated. The second is by considering these load modifying resources as a virtual generator directly analyzed with ICA. At a minimum the first will be explored and the second provided desire and input from the ICA Working Group (ICAWG).
c. Assumptions used in Demo A are provided in the appropriate sections of this report to help inform ICAWG on how ICA is considering distribution system conditions and DER parameters

2. **Common Methodology Across all IOUs**
   a. Through comparative assessment and coordination with the ICAWG the three IOUs worked together to develop more consistency in ICA calculations as outlined in the ACRs.

3. **Different Types of DER**
   a. The ACRs outlined a set of 'typical' or 'baseline' DER profiles to consider in the analysis. In discussions with ICAWG, the IOUs settled on a method to analyze the baseline portfolios using computational efficiency improvements.
   b. The IOUs also provided 'agnostic' ICA values that can be used by DER providers to analyze other DER portfolio combinations.

c. As agreed by the ICA WG, an "ICA translator" was made available for users to determine the ICA values for different types of DER.

4. **Granularity of ICA in Distribution System**
    a. The granularity of the ICA was performed at a line section and/or node level on the primary distribution system as per the original guidance and the ACRs. This means that ICA was analyzed for the high voltage (4 kV to 21 kV) side of the distribution system. Scope of the analysis did not include the service transformers or secondary service to customer premises.
5. **Thermal Ratings, Protection Limits, Power Quality (including voltage), and Safety Standards**
    a. Four major criteria of Thermal, Protection, Power Quality/Voltage, and Safety/Reliability were considered and analyzed in the analysis. The demo project included the components in Table 2-4 of PG&E DRP to the extent feasible and the accuracy of such analysis was validated.
    b. Protection impacts and limits were evaluated with coordination between IOUs on where increased consistency can be achieved. For instance, exploring evaluating both Short Circuit Capability as well as Reduction of Reach versus IOUs evaluating only one or the other.
    c. Included in this report will be identification of any federal, state, and industry standards embedded within the ICA criterion.

6. **Publish the Results via Online Maps**
    a. Currently the IOUs ICA results are published in coordination with or directly in their respective RAM maps. ICA results and load profiles

are also published and available on the Commission's DRP webpage. One of the major objectives of this demo was to gain further alignment with the online maps for which ICA is displayed. The IOUs, in conjunction with ICAWG coordination and input, were able to drive more consistency and effectiveness to the display of data. Downloadable format and mechanism discussions were also performed in coordination with the ICAWG.

b. The information originally provided in the RAM map has much overlap with the DRP ICA data. It will be the intention that the original data of RAM is the default information provided and that ICA data is properly coordinated. This will include reviewing and reducing overlap of new data and making sure interface is user friendly and effective for developers.

7. Time Series or Dynamic Models

a. The demo project analyzed a 576-hour load profile including peak and minimum 24 hour profiles for each month as well as dynamic power flow interactions with time-dependent components of the system. This is a major application of exploration of various approaches such as iterative simulation and streamlined calculation.

8. Avoid heuristic approaches, where possible

a. The IOUs strove to eliminate heurist approaches in favor of dynamic analysis throughout Demo A. Where heuristic approaches are used (i.e., operational flexibility) those methods were determined to be the most reasonable approach using current tools.

9. **Demonstrate dynamic ICA using two DER scenarios including no backflow and maximum DER capacity irrespective of power flow direction**
    a. The IOUs evaluated the distribution system under a scenario in which no power flows into the substation from the distribution circuits, as well as one in which backflow was ignored, and export increased until a criteria limit was reached.

Based on the ACR and ICAWG discussions there are limitations that cannot be calculated within the Demo A Project with respect to secondary voltage service analysis and high voltage transmission line analysis. Discussion of analysis for these parts of the system can be explored in the ICAWG for long term vision, but is out of scope for the demonstration project. Transmission system limitations and analysis would be a good topic of discussion since the demonstration project evaluated reverse flow into the transmission system without consideration of locational transmission system constraints. However, for the scope of this demonstration, calculations of transmission system limitations are out of scope.

2.c Deliverables

Pursuant to the ACRs, utilities shall prepare a Final Report to report the Demo A project activities and to provide documentation of the ICA methodologies and results. In addition, the resulting ICA data shall be made publicly available using online maps and in a downloadable format. The maps and associated materials and download formats shall be consistent across all utilities and should be clearly explained.

PG&E submits this Final Report for Demo A. In this final report, the objectives, methodologies, results and learnings of Demo A are described. The online map is still being developed and will be made available to the working group upon readiness.

3 SELECTED DISTRIBUTION PLANNING AREAS

3.a General Description

A main goal of Demo A is to ensure a streamlined analysis that can analyze vast amounts of distribution feeders in the PG&E territory. This is extremely important as the PG&E electric service territory is 70,000 square miles with 5.5 million customers across 3,200 distribution feeders and 140,000 miles of distribution lines.

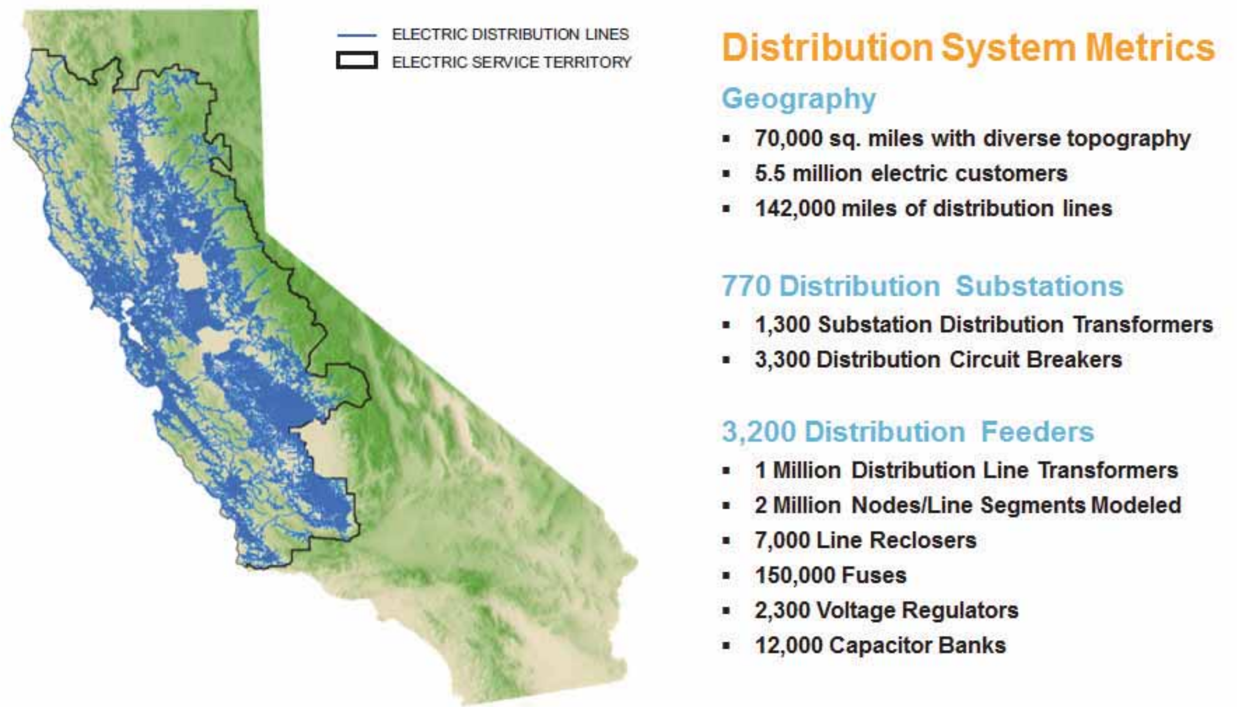

Figure 1: PG&E Electric Distribution Assets and Coverage

Demo A project locations include two Distribution Planning Areas (DPAs) that cover a broad range of electrical characteristics. The two DPAs that are proposed to be evaluated are:

1) Chico (Urban/Suburban)
2) Chowchilla (Rural)

The locations within PG&E territory are shown in the figure below with Chico circled in Blue and Chowchilla circled in Red. The rest of this section explains the differences of the two DPAs and the electrical characteristic variation.

Figure 2: Selected DPA Locations for Demonstration A

These two DPAs represent one urban/suburban and one rural DPA within the PG&E territory. The intent of picking a DPA from each of these categories is to get varying characteristics in which to evaluate varying conditions in the system. The other goal is to drive coordinated learnings with the other demonstration projects. This led to the selection of the Chico and Chowchilla DPAs. Evaluation of the characteristic variation was performed to see if they were sufficiently diverse across the included feeders. That evaluation is below. Here is some general information about the DPAs:

Table 1: DPA Summary

	Chico	**Chowchilla**
Location	Butte County (Urban/Suburban)	Madera County (Rural)
Substations	10	4
Feeders	x37-12kV / x4-4kV	x20-12kV
Customers	125,000	13,000
Recent Historical Peak	235 MW	155 MW
Customer Type	80% Residential, 5% Agricultural, 15% C&I	60% Residential, 30% Agricultural, 10% C&I

3.b DPA Characteristics Comparison

The following is the analysis performed to understand the electrical diversity in the feeders within the two DPAs. The group of figures below depicts statistical variation of characteristics for each feeder within the group set. The group sets are:

- **"System"** – All distribution feeders
- **"Chico"** – Only feeders in Chico DPA
- **"Chowchilla"** – Only feeders in Chowchilla DPA

The electrical characteristics evaluated are:

- **Total Length of Circuit** – This is the summation of all the line length for each line on the feeder and is important to understand how ICA manages shorter circuits versus longer circuits

- **Maximum 3-phase Resistance** – This is the maximum resistance of the three phase line section which helps determine the range of possible worst case resistance a circuit can provide DERs.
- **Voltage Regulator Count** – The amount of regulators helps understand the complexity of voltage management on the circuits. Smaller counts mean easier voltage management and larger means more complex management of voltage.
- **Capacitors** – The amount of reactive support provided by capacitors on the circuit to reduce losses and help voltage. More capacitors mean more complex voltage management and more possible losses on the circuit.
- **Protective Recloser Count** – The recloser count will help provide possible complexity of protection schemes on a circuit. The more reclosers the easier it may be for a DER to impact the protection coordination on the circuit.

The statistical variation is shown with box and whisker charts to show the distribution and range of each characteristic between the groups. With these two DPAs it can be seen that a majority of the ranges of these characteristics are covered. The first three quartile ranges are covered across these categories as well as a majority of the 4th quartile. It is through this analysis that PG&E is confident that these DPAs provide the required "broad range" of electrical characteristics required by the ACR.

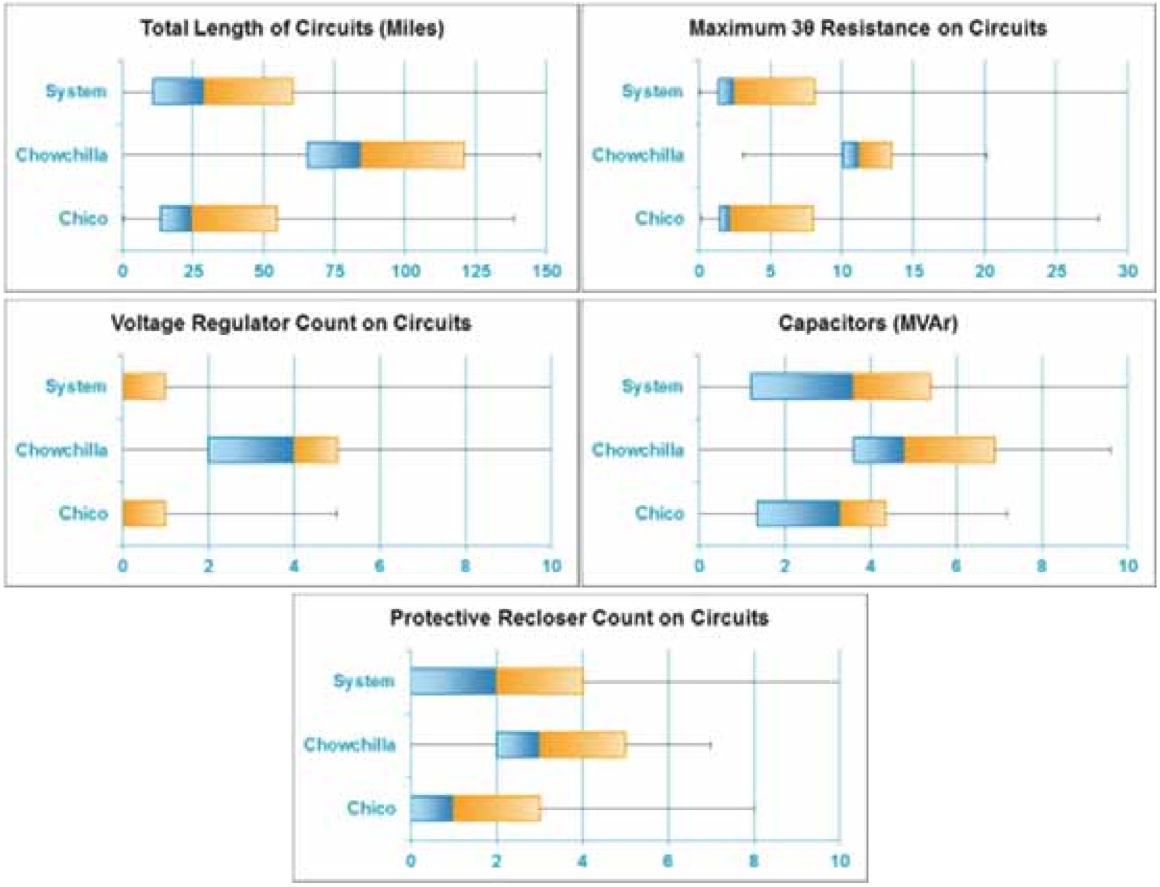

Figure 3: Statistical Variation of Electrical Characteristics

A load profile variation analysis was performed on the two DPAs. This analysis used some of the preliminary enhanced load profile data within the EPIC 2.23 project. These load profiles are aggregated profiles for each DPA which is built on hourly meter data for the customers within the DPAs. The different percentile shapes show the probability of hourly load throughout the year as a percentage of the peak. Chico is representative of typical residential loading with summer peaking driven by temperature. Variation between the tight bands in the winter versus the wider bands in the summer will be good for analysis. Chowchilla is representative of rural loading driven by non-residential load. This area is good for analysis to understand the low loading times which would push more reverse flow from generating DERs. These profiles can be seen in the figures below.

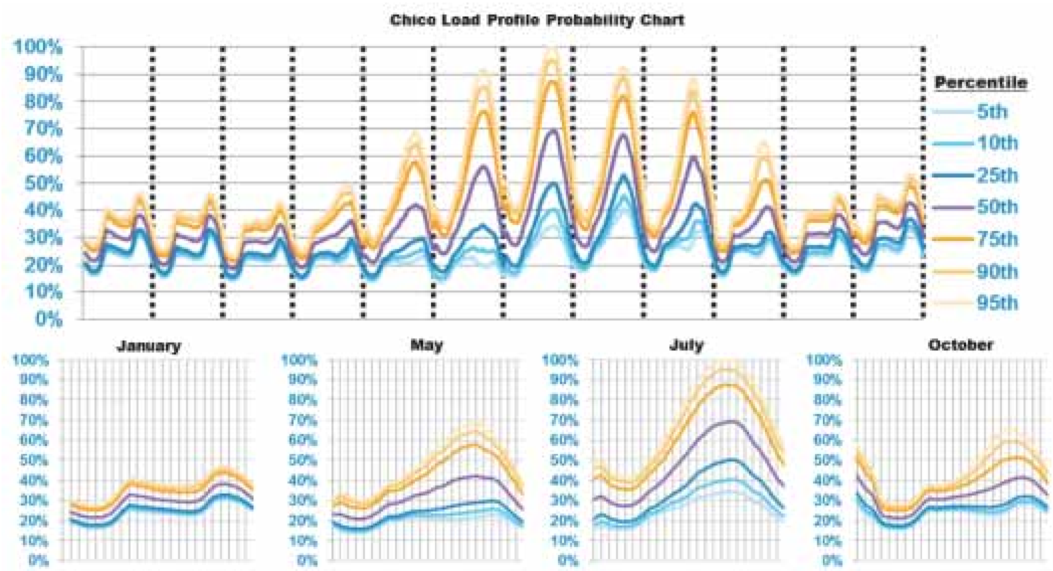

Figure 4 - Chico Load Profile Variance

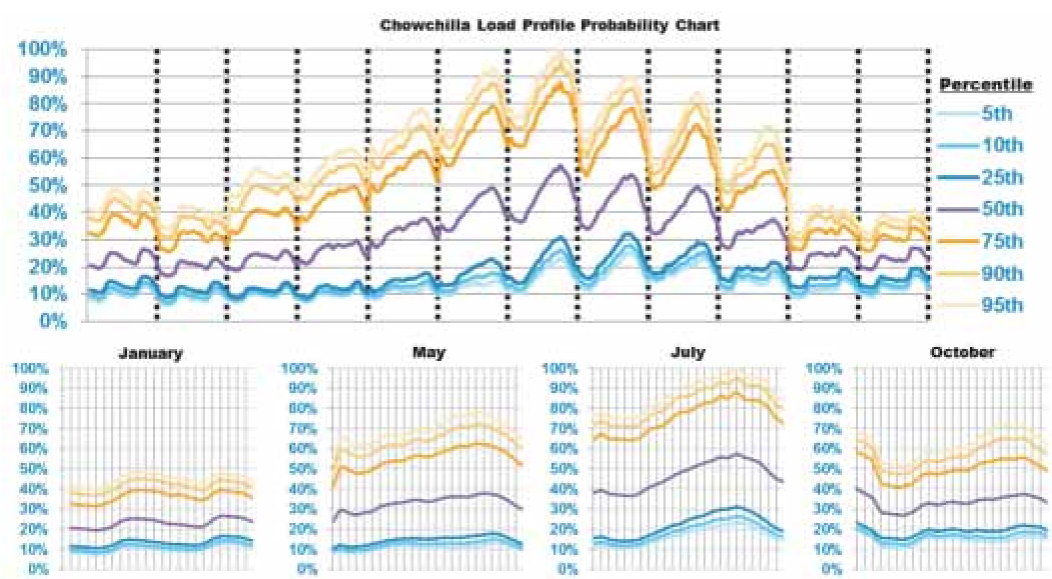

Figure 5: Chowchilla Load Profile Variation

4 METHODOLOGY

4.a General Description

This chapter describes the methodologies implemented in Demo A. Demo A is a developmental step towards Utilities' final proposals for a common ICA methodology that can be used to update the DER hosting capacity at regular intervals. Being consistent with the ACR requirements, the modified baseline methodology used in the Demo A is described below, in four general steps:

1. Establish distribution system level of granularity
2. Model and extract power system data
3. Evaluate power system criterion to determine DER capacity
4. Calculate ICA results and display on online map

Figure 6 illustrates the general ICA methodology process diagram. After the system model data and load data are extracted from various databases, the distribution circuit models are developed in the power flow analysis tool. Several applicable power system criteria are examined based on either pre-defined equations or iterative power flow analysis in order to identify the maximum capacity for hosting DERs at each node. The DER hosting capacity for each criterion is calculated independently and the most limiting values are used to establish the final integration capacity limit for the nodes. In addition, the upstream components such as line devices and substation transformers would help provide limiting constraints to the final IC. The detailed ICA results will be made publicly available online and in a downloadable format.

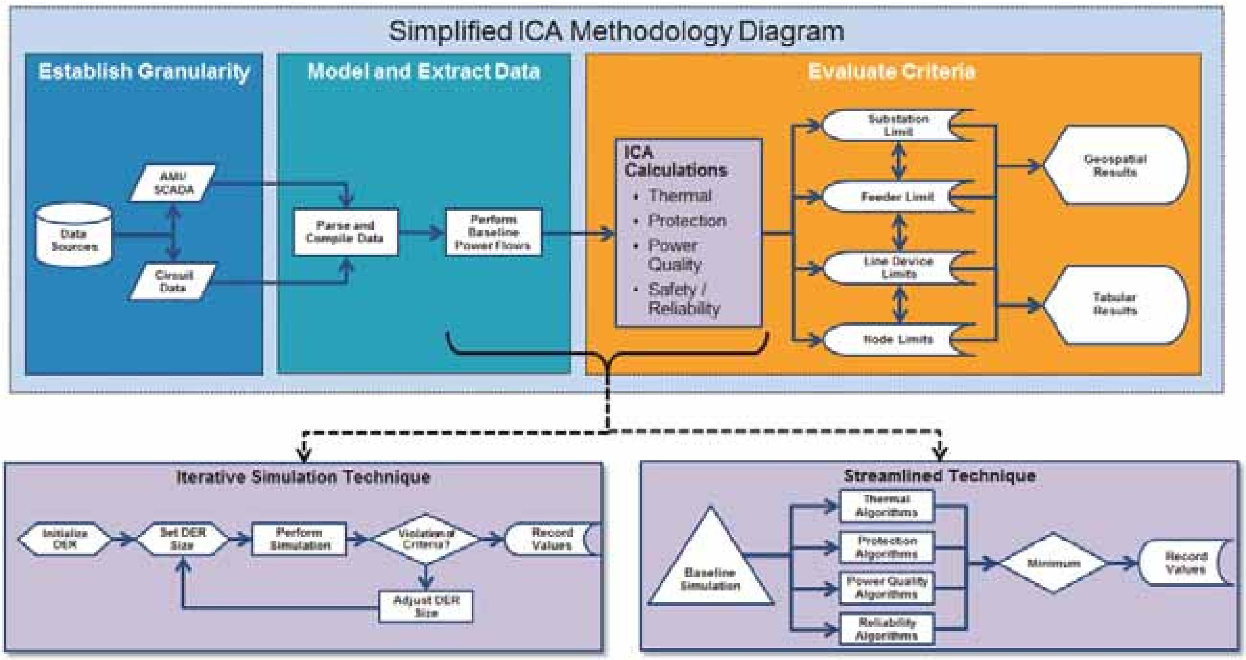

Figure 6: ICA Process Diagram

Streamlined Method

The streamlined method uses a abstraction approach, applying a set of equations and algorithms to evaluate power system criteria at each node on the distribution system. The streamlined method first performs a baseline power flow simulation to acquire the initial conditions of the circuit that will be used in the streamlined calculations. These conditions can be but not limited to electrical characteristics such as thermal ratings, resistance, voltages, current, fault duties, etc. The streamlined method then evaluates the full set of criteria, including thermal, voltage, protection, and safety limits independently to determine the maximum hosting capacity at a given node or component of the system. Simpler methods utilized in the streamlined methodology may not capture some of the more dynamic effects on the more complex circuits. However, the ability to utilize simpler equations and algorithms within a database can enable faster computations on large datasets.

Iterative Method

The iterative method performs an iterative power flow simulation at each node on the distribution system. The iterative method solves for thermal and voltage conditions simultaneously using power flow simulations. Fault flow simulations are used for protection criteria not dependent on power flows. Due to the large number of iterations required, iterative analysis can result in long processing times, especially when expanded to large numbers of distribution circuits. However, the use of an iterative simulation parallels what the IOUs would perform as part of an interconnection study. This technique is expected to provide more confidence in representation of integration capacity on more complex circuit conditions.

Layered Abstraction Approach

Important to this whole process and regardless of calculation techniques is the concept of layered abstraction. By defining layers that represent electric circuit system hierarchy, the explicit criteria calculations can be made within a layer independent of another layer's calculation. This helps organize the results in a way that can inform specific limitations to a single point of interconnection or broader limitation to a feeder or substation for system planning. Performing the analysis using abstract and layered thinking is helpful for two reasons:

1. Enabling further improvement of ICA's scope and granularity
2. Streamlined processing for vast datasets

Figure 7 visualizes the integrated process of evaluation across the criteria at each layer. This integrated technique is important to get results for both node specific limitations and substation level limitations. For instance, locational results can be limited by a higher level constraint such as the thermal limitation of a substation transformer, therefore limiting the total amount of possible DER that can be hosted on the downstream feeders and line sections.

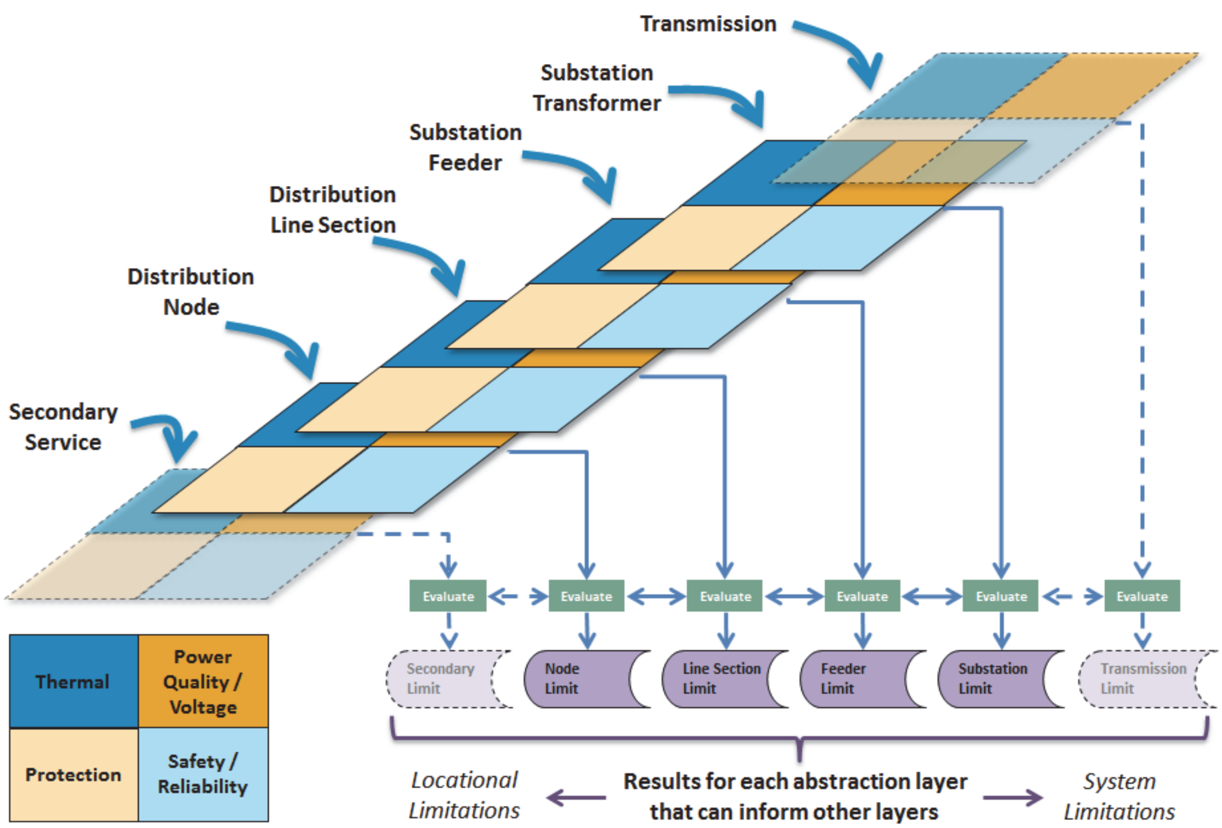

Figure 7: Layered Abstraction Component

4.b Establish Distribution System Level of Granularity

The first step in PG&E' s ICA methodology is to determine the distribution system level of granularity. The detailed distribution cirucit models in PG&E' s toolset allowed for data to be extracted from distribution line sections and even down to each nodes on the primary side of service transformers.

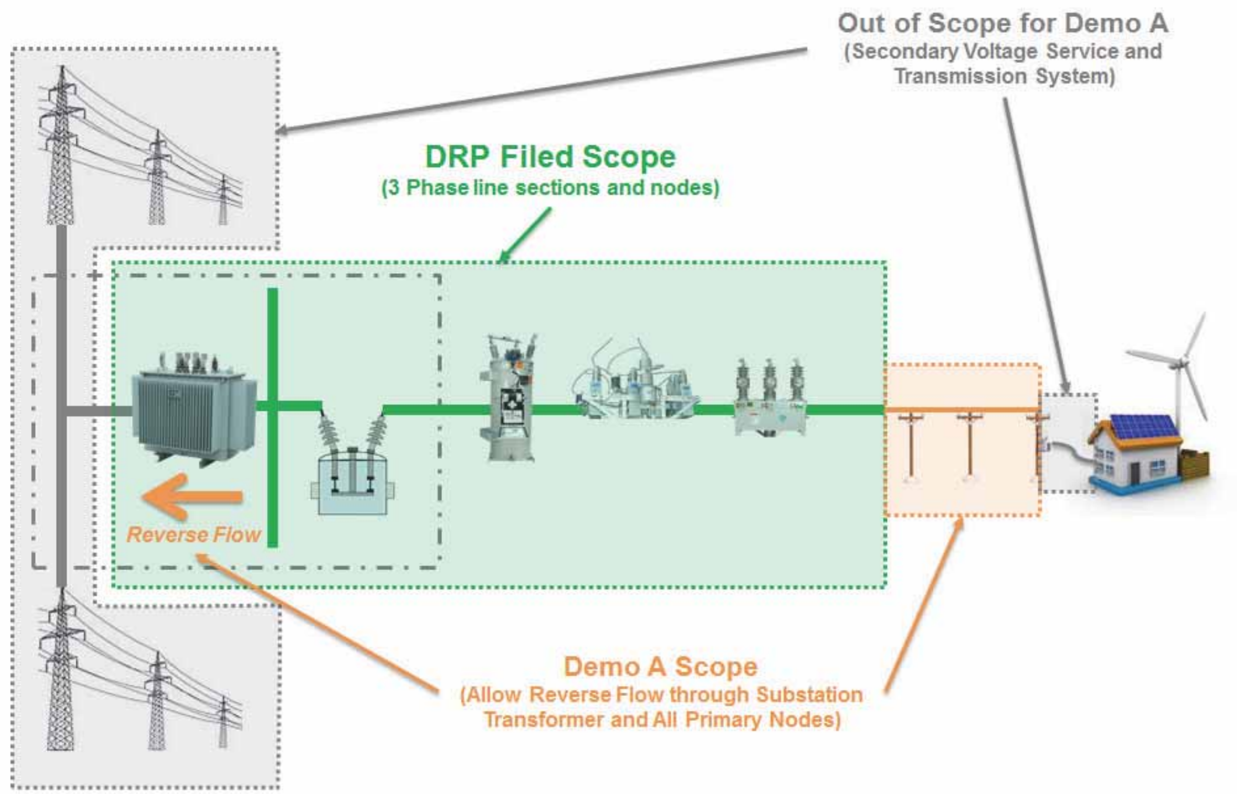

Figure 8: Granularity of ICA for PG&E in July 1 2015 filing

This level of granularity allows PG&E to obtain a granular set of data which can determine the capacity limits for complex feeders, such as long rural feeders. Granularity is not just limited to downstream details, but upstream details as well. PG&E' s dataset was sufficient to include analysis up to the substation transformer bank. This is where layered abstraction was useful for inclusion of additional components. PG&E' s distribution circuit models are only modeled to the medium voltage bus of the substation. This means that the substation transformer is not specifically modeled. Without performing an evalaution of the transformer in abstract outside of the cirucit models, PG&E would have been limited in the ability to determine limitations from the substation transformer. This was important to consider as there are substations in the PG&E system where substation transformers are more thermally limiting than the circuit breakers and/or getaways that feed the distribution circuits.

One of the main goals of the DRP was to provide insight into very granular locational DER capacity on the distribution system. PG&E reccomends guidance to explore transmission level analysis in the future to ensure transmission capacity limits are considered as well. If transmission conditions are not considered, locational ICA results totaled together may lead to over estimation of total system DER integration capacity.

It is important to acknowledge these bounds of the analysis and data. As mentioned, without doing so could lead to users compounding results to various system levels that may not have been included. For instance, users could add feeder level results for all feeders at a substation. Without understanding the transmission limits upstream, results could lead to improper siting and sizing decisions.

Figure 9 below is a physical illustration relating the four main components on distribution power lines to modeling components. It is meant to create a baseline for defining what "node", "line segment", "line device", and "line section" mean in context of ICA and the tools. Figure 10 represents these four components as they relate to a substation and how they might be modeled in the tools.

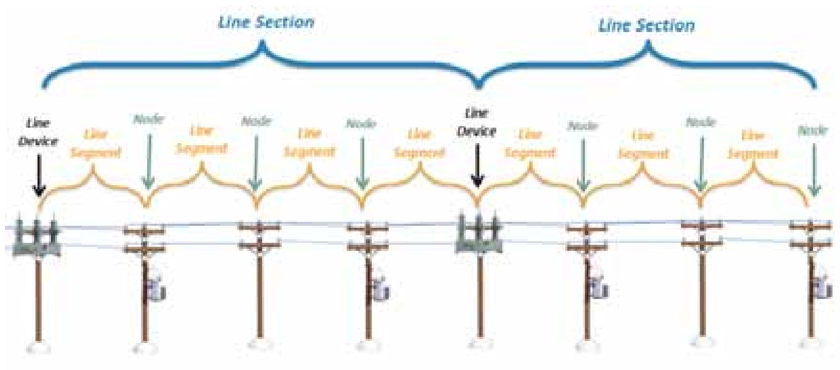

Figure 9: Analogy of Nodes, Line Segments, and Line Sections

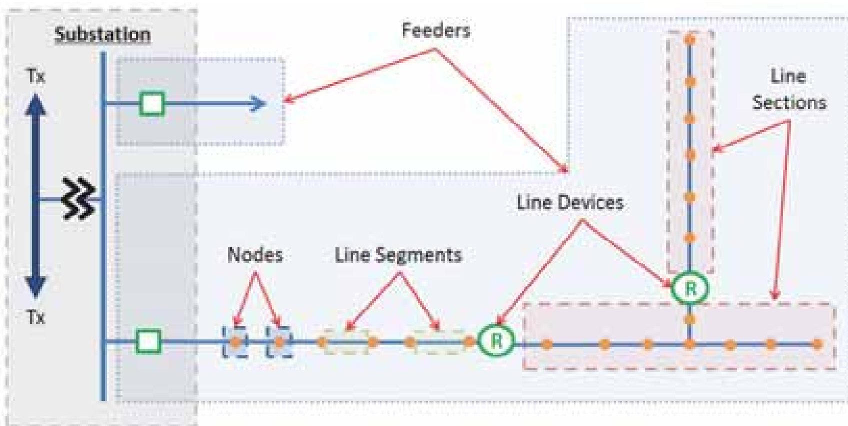

Figure 10: Representation of Nodes, Line Segments, and Line Sections

Figure 11 below provides a visual of how the results of ICA can be associated to components in the mapped model. The figure depicts how the analysis is applied at the three major levels of granularity on the distribution system (substation bank, feeder, and line section (by device)).

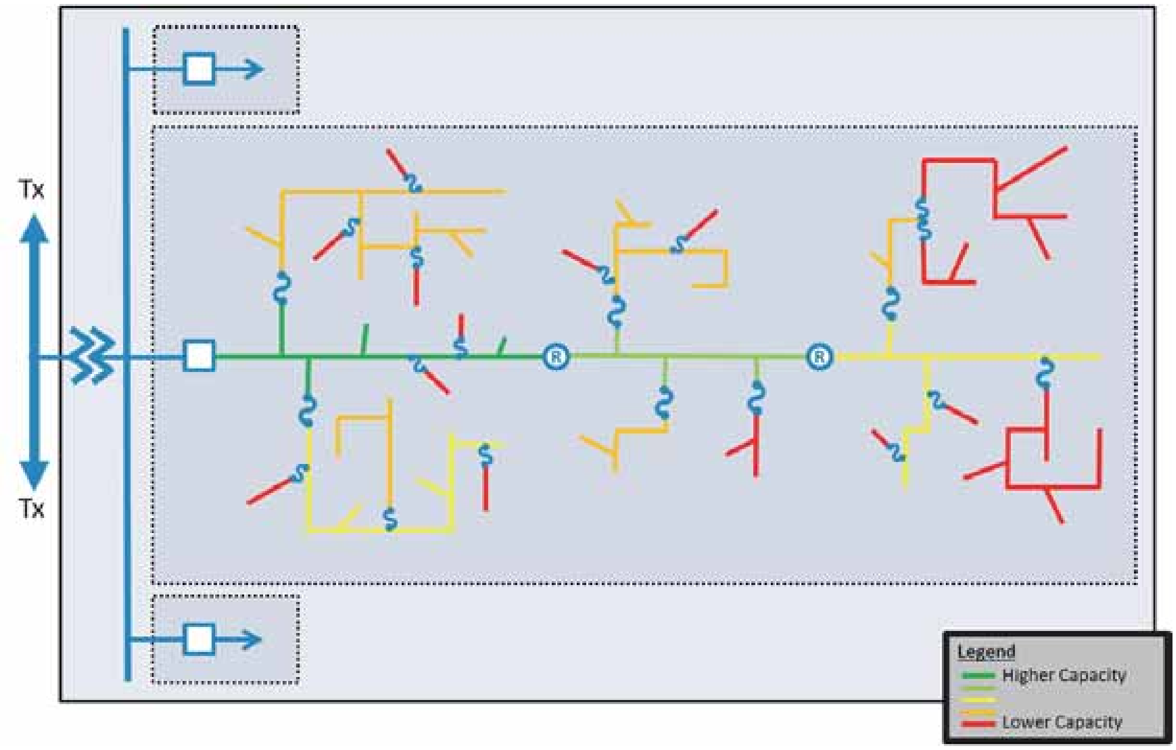

Figure 11: Intra-circuit ICA simplified visualization

Dataset and Tool Capabilities

Knowing what data and tools that are available is important in order to structure the process of finding results. This may differ utility to utility, but below is an inventory of the data and tools used by PG&E.

Datasets

- **Electric Distribution Geographic Information System (EDGIS):** The circuit model is built from detailed data, as described in level of granularity. It contains the thermal ratings for conductors and devices, device and equipment characteristics, and load and generation customer details.
- **Load Shapes and Forecasts (LoadSEER):** Load profiles and forecast information that can be applied to the feeder loads and generation.

- **Supervisory Control and Data Acquisition (SCADA):** SCADA data is leveraged by LoadSEER to develop the demand profile for each circuit, which is then aggregated up to the substation bus.
- **Advanced Metering Infrastructure (AMI):** Interval metered data is extracted for the customers on every circuit and load is allocated to the circuit model and utilized in LoadSEER for profile evaluation.

Tools

- **CYME Gateway:** used to model and update distribution systems including but not limited to conductors/cables, line devices, loads and generation components
- **CYMDIST:** the Power Flow Analysis Tool used to perform load flow analyses in order to determine electrical operating conditions of the distribution system.
    - CYME's new ICA module was also utilized specifically for iterative ICA
- **Python:** the dynamic object-oriented programming tool used to automate both the streamlined method and the iterative method as well as perform data analysis within the CYMDIST software
- **LoadSEER:** the load forecasting analysis tool used to develop electric distribution forecasts and locational demand profiles throughout the system
- **SQL:** the informational management tool used for ICA results repository and post simulation analysis. Normal text/spreadsheet data handling is insufficient due to the high level of granularity of the data.
- **ESRI ArcDesktop:** the maps and geographic information tool used for creation of the geospatial ICA results visualization on the PG&E RAM map

Utilizing LoadSEER and the underlying hour interval load profile data enabled a rich set of hour-by-hour constraints which were analyzed against hour-by-hour DER profile values. Modeling the load profile data can be performed in many ways and can vary depending on a utility's source of load information. If a utility is rich in Supervisory Control and Data Acquisition (SCADA) devices and monitoring points, then extracting and utilizing SCADA may be best. For utilities rich in Advanced Metering Infrastructure (AMI), aggregating and analyzing AMI could be the better approach. PG&E utilized and is enhancing a hybrid approach in which AMI, SCADA, and customer information is pulled together dynamically to create a set of statistically based power profiles within the distribution circuits.

Utilizing CYMDIST and its geospatial application of feeder modeling is an extremely useful tool to getting granular results for ICA. PG&E's ICA results would not be as robust and granular without CYMDIST and the modeling gateway that transforms GIS data into power flow models. Another advantage to utilizing CYMDIST is its advanced functionality in Python scripting. The Python scripting allowed for customized utilization of internal tool functions to perform the necessary evaluation, data extraction, and batch processing. More recent advancements from CYME have produced a special Integration Capacity Module that was directly utilized to aid in the iterative approach to ICA.

4.c Model and Extract Power System Data

In order to ensure transparency and consistency within the methodology, the various assumptions and starting point parameters must be expressed. This will ensure parties that are looking to replicate or create comparable results on different datasets know what parameters to implement.

Various data points are used to help inform the power flow analysis. While some parameters are static and do not have any significant variance (i.e. conductor impedance), there are some parameters that could have some variation and need to be set for the analysis (i.e. starting voltage at substation). The sections are a listing of some of the assumptions and starting points PG&E used in the analysis.

Evaluating the power system criteria for streamlined integration capacity requires modeling and extracting data from power flow models. This data extraction is currently accomplished through using the Python scripting capabilities within CYMDIST. PG&E has leveraged these scripting capabilities to automate and perform batch load flow, data extraction, and zone hierarchies within the circuit for publishing granular inter feeder results.

When extracting the data, it is important to record and consider the system hierarchy to ensure calculated values can be compared and integrated across the layers. For instance it is important to know what nodes are downstream of a line device, what devices are downstream of other devices, or what line devices are on what feeder. Extracting this information is necessary for proper determination of the final locational integration capacity results.

Geospatial Network

PG&E models each of its distribution feeders using its Power Flow Analysis Tool. This tool analyzes power flow on distribution feeders by modeling conductors, line devices, loads, and generation to determine impacts on distribution circuit level power quality and reliability. Similar to how SCADA improves power profiling, Geographic Information System (GIS) mapping improves the ability for PG&E to analyze its system assets. GIS mapping traces the distribution system down to the service transformer level. Knowing the composition of a particular series of line conductors as well as their relative location from a power source allows engineers to determine various power system details to a specific location on the distribution feeder. These electrical models are updated weekly using the CYME Gateway to reflect changes that occur on PG&E's distribution system.

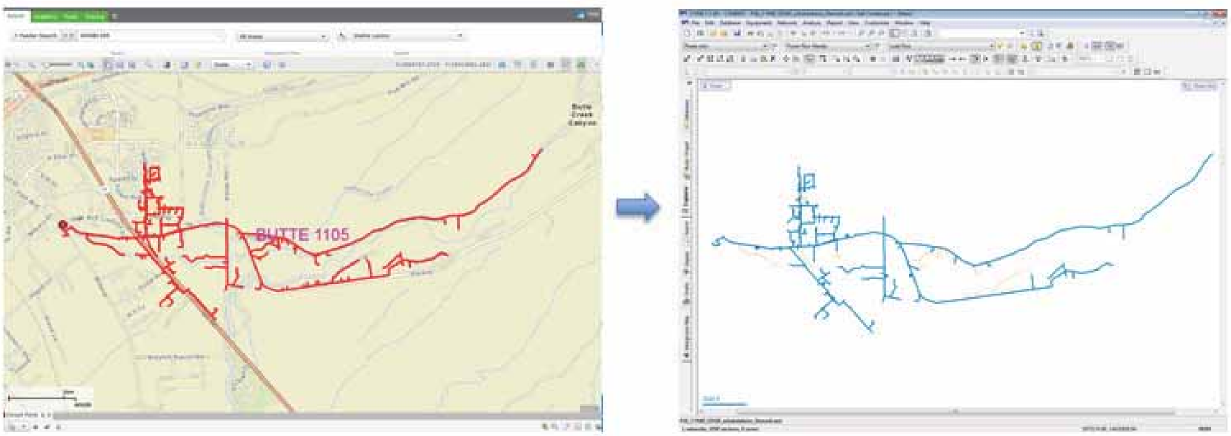

Figure 12: GIS Mapping Translation to CYMDIST Models

Secondary Service

At this time secondary services are not modeled in CYMDIST. This will be additional work to the gateway as well as work to compile and translate into the GIS system. The power flow models stop at the primary side of the service transformer. Because of this the ICA is limited to evaluated primary distribution side issues and can't determine any secondary service issues. This will be important for consideration in the Electric Rule 21 interconnection tariff that relies on screens about the impact on the secondary service.

Substation Model

Historically, PG&E's distribution circuits in CYME are modeled from the circuit breaker at the substation down to the primary side of customer service transformers. PG&E is in development of upgrading the CYME Gateway to translate the GIS data from the new GIS system being implemented. Included in the scope of this project is to expand the models to the substation components that electrically connect feeders on the same substation transformer. This project is still in development and Demo A looked to explore the ability to include and utilize the substation models. While the substation model is not critical to all components of ICA, it may help in providing some more detail in the Power Quality and Protection criteria to understand adjacent feeder impacts. Figure 13 shows how CYMDIST utilizes a one-line model layer for subsation components versus the geographic model for distribution lines.

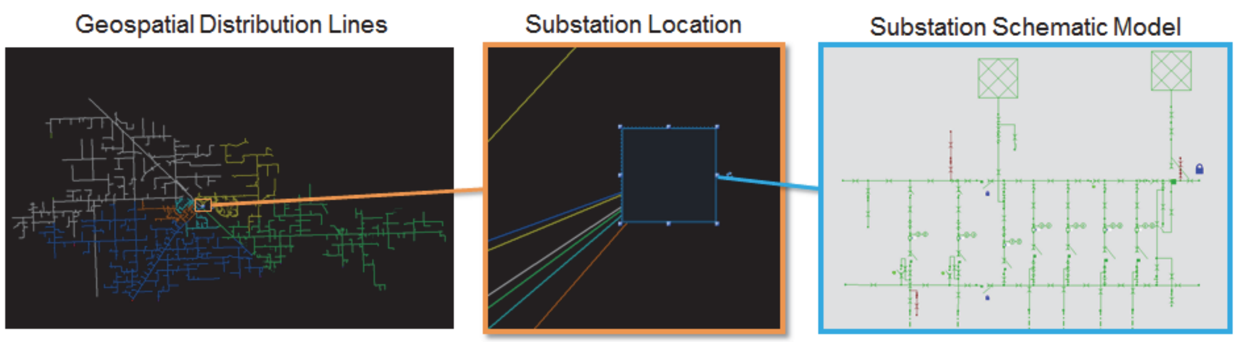

Figure 13: Substation Models in CYMDIST

Initial modeling and simulations have shown much difficulty in modeling the substation and incorporating directly in the analysis. Two learnings about modeling the extra complexities of the substation model:

1. Substation modeling requires simulation and convergence of multiple feeder models in unison versus separately. This increases computation times for each simulation.
2. Modeling the Load Tap Changer (LTC) increases the complexity of the model and does not always allow for convergence of power flow solution to solve

Because of the reasons listed, PG&E decided that the substation models added too much complexity at this time to achieve meaningful results. The main effect of the LTC and behavior of substation was mimicked to ensure hourly results that made sense. Utilizing the techniques of Layered Abstraction does allow PG&E to consider the substation load conditions and constraints. PG&E is continuing to enhance the models to include the substation models and will incorporate to ICA as necessary and feasible. While the substation model may be helpful, PG&E does not feel the direct modeling of it is necessary within the analysis at this time.

Substation Source Parameters

Two main components are necessary for the model source (1) Operating Voltage and (2) Source Impedance.

1. Starting Voltage
    - Sliding scale of voltage from 1.00 to 1.05 per unit
    - Sliding scale depends on load through substation which simulates the load tap changer
    - Equation used: $V = 1 + 0.5 * (kW[t] / kW_{peak})$
2. Source Impedance
    - Extracted from transmission network model distribution bus impedances

As mentioned, the substation LTC can be simulated in the model by dynamically changing the set point of starting voltage based on substation transformer loading. The source impedance helps simulate what the conditions would be based on the transmission characteristics at that location.

Feeder Configuration

Feeder configurations in the model are set to the normal as planned switching states. These configurations are used in the interconnection study process.

Feeders are not often permanently switched and, when switched in emergency, Operation Engineers evaluate and study for possible issues. Future enhancements of ICA and automated analysis techniques will explore automation of possible abnormal switching configurations. The vast amount of possible switching configurations and computational burden will be an interesting hurdle. This is why PG&E proposed the method of evaluation called "Operational Flexibility" to estimate when possible issues could occur without performing millions of permutations on top of the already lengthy ICA analysis time. This topic is discussed further in section 4.d.v.

Balanced versus Unbalanced Power Flow

Power flow algorithms have different approaches towards calculating and converging on power flow solutions for the model. The main reason for using one versus the other depends on the availability of phasing data. If phase data is not available, then balanced would be the appropriate technique since the actual phasing imbalance is not known for the circuit. If phasing is available then the appropriate phase conditions can be solved for and provided with an unbalanced power flow.

Currently PG&E does not have the appropriate phasing information for unbalanced power flows so the balanced power flow option is used. In order to ensure proper comparative analysis the option to run either was included.

Spot Load Demands

Each distribution service transformer is modeled as a "spot load" in CYMDIST. Historically these spot loads would contain customer specific information which would include monthly consumption values in kW-h. For the model to run power flows, specific kW demand values are needed for each spot load. Load allocations would be run to allocate a specific known demand at the substation to each spot load based on the monthly consumptions.

New Smart Meter data can be utilized with the known hourly consumptions to increase accuracy of allocations to a specific hour. Load allocation methods are still utilized to make sure the spot loads reconcile to a known demand at the substation. This hourly data helps improve the granularity and accuracy of the power flow models. The standard load allocation module within CYMDIST is utilized for the final allocation.

Load Profile Development

The following figures provide a visual example of the load shape profile versus a full detailed yearly profile. Figure 14 shows the real-time hourly profile for a year represented by 8,760 hours that show the actual demand for each hour of the year. Figure 15 shows the load profiles, which are built from the new dataset within the EPIC project. The analysis of this data allows for the creation of the simplified 576 profiles as required for the streamlined ICA assessment.

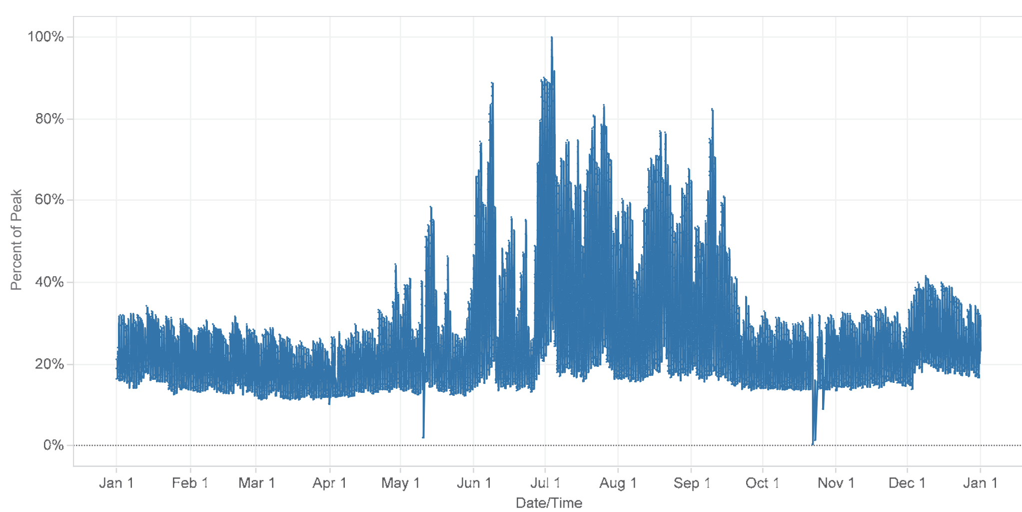

Figure 14: Historical SCADA (8760 hours)

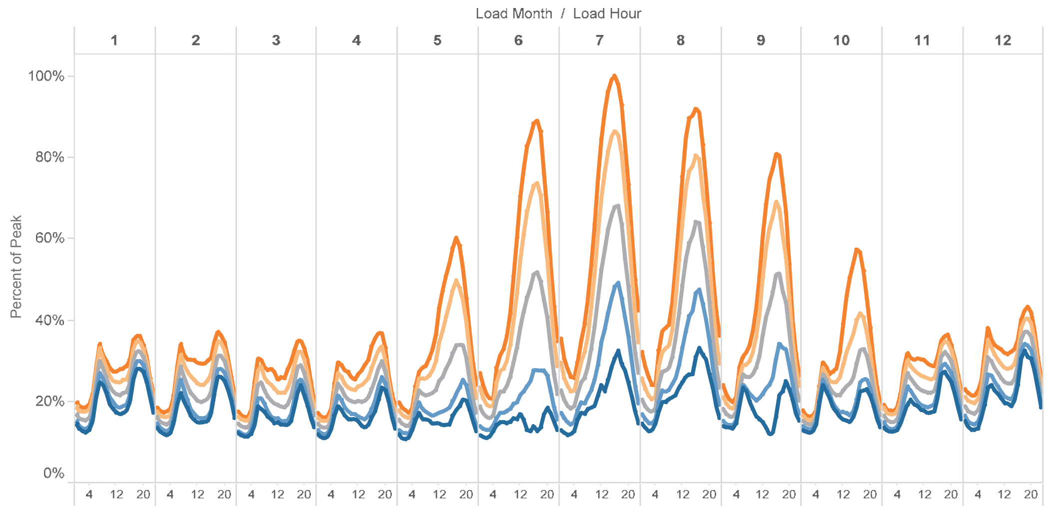

Figure 15: Statistical Load Shapes built from Historical Data (288*X Hours)

PG&E has been using locational load shapes in LoadSEER since 2010. Smart Meter history has penetrated enough of PG&E territory and has about three years of history which has provided new opportunities to enhance the load shapes. EPIC 2.23 analyzed all this history to update and enhance the locational load shapes. With this new dataset, load shapes can be built and analyzed at the customer premise or aggregated all the way up to whatever level desired.

In this process a few things have been realized. One of the most important learnings is that Smart Meter information cannot be used on its own to assume specific conditions on the grid at much higher levels. There are a few contributors to this issue:

1. Not all customers may have Smart Meters
2. Most customers are hourly consumptions (kW-h) and not demands (kW)
3. Other components to the grid impact substation power such as losses and capacitors

SCADA helps for reconciling actual conditions and adjusting the shapes to observed conditions. Having the shapes known by specific customer types also helps assign shapes to customers that don't have Smart Meters. PG&E has valued the experience with load shapes versus just using raw data given this provides a better understanding of variability and causation. Raw SCADA and Smart Meter data needs to be scrubbed for anomalies as well (i.e. bad communication, transfers, outages, etc.). It will be important to continue understanding how best to utilize this data to understand variability and uncertainty and not get too caught up in deterministic load values.

For Demo A, two sets of 288 hour profiles were used:

1. 90th Percentile – This profile represents the high load scenario
2. 10th Percentile – This profile represents the low load scenario

Evaluating both 288 profiles helps understand the range of capacities in each scenario. Generation ICA may be more limited due to loading and thermal limits in the 10th percentile low load case. The 90th percentile high load case will help understand how much can be hosted during higher load periods which also may be more limited by voltage conditions. The reverse can be said for load ICA.

Load and DER Forecasts

Utilizing efforts in EPIC 2.23 has allowed coordination with ongoing work with Integral Analytics to incorporate directly into PG&E toolsets in order to have more access to system data. One of these data points is the load and DER forecast. This component is not part of the methodology, but more so the setup of and input to the model being analyzed. The forecasts created in the planning process can be fed into the models to adjust the loading accordingly within the circuit.

Typically during the planning process the engineers manually adjust and consider the load growth and specific interconnections within feeder models that are coming online in the coming years. Due to this being a mostly manual process and ICA being heavily automatic a simpler approach was taken for incorporation of the load forecasts in Demo A. The feeder profile to which the circuit is allocated is adjusted based on the new load and DER forecasted for the circuit. PG&E expects the incorporation of the load and DER forecasts into ICA to evolve and get better as more work is done on integrating the distribution planning tools.

PG&E views three general methods of considering forecasts with ICA each with increasing difficulty, respectively, to consider:

1. Subtract forecast amount from ICA results
2. Net forecast into the feeder load profile
3. Stochastically consider forecast on the feeder

Method 1 requires less processing, but given the results are locational for each node and do not consider distributed effects PG&E felt this was not a good choice. Any type of allocation that would be done to distribute forecast to locational ICA seemed to be better applied in Method 2.

Method 2 requires slightly more processing due to each year of forecast needing a new simulation. The netting of the forecast in the feeder profile allows for a distributed nature of the forecast to occur given that the circuit is reallocated based on the feeder load.

Method 3 requires the most amount of processing as it needs to analyze each new randomized placement of resources. The current analysis already takes a significant amount of time for single placement across multiple hours. This method has the most amount of accuracy and consideration to uncertainty out the three methods. The direct placement and simulation of expected forecasts and the uncertainty of where they will be placed is a good blend of interconnection certainty and planning uncertainty.

PG&E decided on method 2 within Demo A given that 1 did not seem to be intuitively applied from a planning sense and method 3 was not technically feasible given IT resources and timing of project. More discussion within the ICAWG can discuss the incorporation of DER growth and how its performed.

DER Placement

In its current stage the ICA is more focused on large centralized DER impacts and the implementation into the interconnection process. Every new DER location is analyzed independently of any other new DER being placed on the circuit. This approach is helpful for interconnection purposes, but not much so for planning purposes. Both ICA methods at this stage has explicitly only been utilized in a centralized DER approach. The layered abstract nature in the processing does help in some sense, but does not capture the full aggregate impacts of large amounts of small distributed DER forecast. This is especially true for voltage impacts.

Iterative techniques would have to rely on some stochastic or statistical consideration of DER placement for understanding distributed DER impacts in a planning sense. The streamlined technique does not directly place DER in the model and thus requires an algorithm to consider the distribution of placement within the equations. EPRI's streamlined approaches have been doing so and more exploration into their specific techniques can be explored which utilize a Weibull distribution to consider the impact to voltage from a forecast of PV on a circuit.[4]

DER Parameters

In order to determine the impact of DER on the system, the analysis must consider a few basic parameters of the DER. The following is the list of parameters that were considered:

- Real Power Consumption (Load) and Real Power Injection (Generation)
    - Results for ICA are to be agnostic to DER with final ICA as hourly results
    - The analysis does not necessarily work in the manner of assuming a specific reduction of output/input at a given hour. It evaluates what level of output/input creates an expected violation at each hour.
    - DER specific output is proposed to be considered in post analysis based on the hourly results to get specific DER results
        - This topic is discussed further in section 8.b
- Power Factor
    - Base results will be run assuming a unity power factor
    - Section 8.a discusses analysis at non-unity power factors
- Fault Contribution (for generators)
    - Fault contribution will assume 120% of nameplate for inverter technologies

4.d Evaluate Power System Criteria to Determine DER Capacity

[4] See Page 6 of: EPRI, January 2016, Integration of Hosting Capacity Analysis Into Distribution Planning Tools http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002005793

Power system criteria are the principles that determine the capability of the system to integrate DER. As required by the ACRs, four major categories of power system criteria are considered in the Demo A to determine the DER integration capacity for the nodes and line sections on each distribution feeder. These four criteria are thermal rating, power quality and voltage, protection system limits and safety and reliability standard of existing equipment. Each power system criterion is evaluated independently and the most limiting values are used to establish the integration capacity limit for the corresponding node/section. The process for these calculations is also described in this section.

4.d.i Calculation Techniques

The ICA calculation techniques provide approaches towards evaluating distribution system limits to host DER across the entirety of a utility's service territory. The specific technique to the methodology has two main goals to ensure a successful and scalable analysis for the DRP which are (1) streamlined efficiency and (2) improved detail and granularity. These two objectives in general can lead to diverging paths for a methodology, but the goal of the demonstration project is to determine if there is a best path forward to strike a balance between the two. There are two calculation techniques being explored within Demo A. These are:

1. **Streamlined Calculation**
    - Promotes streamlined efficiency through reduced simulation and principles of abstraction
    - Simplified or abstracted evaluation based on algorithms with input from a baseline power flow
    - Requires less processing resources. Enables more batch output insights (e.g., for DER planning where multiple scenarios are needed)

- May prove less precision in accuracy since resource is not directly modeled

2. **Iterative Simulation**
   - Promotes detail and accuracy through direct modeling and observing simulated conditions
   - Increased confidence in accuracy due to direct modeling of resource
   - Better for more accurate representation of DER impact to electrical conditions of circuit.
   - Requires powerful computing through simulation of iterative placement/upsizing of DER in model to simulate very precise conditions with many power flows

The working group and demo projects are paths to test, compare and improve methodologies. Multiple techniques enhance innovation to tackle problems with a wide range of complexity, especially at this early stage. We may find that an iterative solution can serve more complex problems, while a streamlined calculation can serve simpler problems. Moreover, when multiple methods return similar results, we have increased confidence (triangulation, or convergent validity). A blended approach may be more intelligent, less risky and more effective in enabling innovative, valid and efficient outcomes. It can also help in meeting the objectives of the use cases including enabling ability to expedite the interconnection process.

4.d.i.1 Streamlined Method

The streamlined approach applies a set of streamlined algorithms for each power system limitation category/sub-category to evaluate the DER capacity limit at any node of the distribution circuits. It performs analysis more efficiently by not requiring direct simulation of DER to observe impact. This helps to enable system wide scenario analysis with much less processing requirements. For instance, batch power flows are performed to get electrical conditions and data such as but not limited to ampacity flows, voltages, fault duties, and impedances. The final results are determined by inputting this data into the streamlined algorithms to determine the integration capacity for each limitation.

Figure 16 illustrates how each power system limitation criterion is evaluated though power flow or short circuit analyses and how the final ICA values are established based on the most limiting individual ICA values. The algorithms are repeated for every node of each circuit as well as for different power flow scenarios. During the reverse power flow scenario, the safety/reliability criterion (i.e., operational flexibility) will be excluded so that the study will allow reverse power flow.

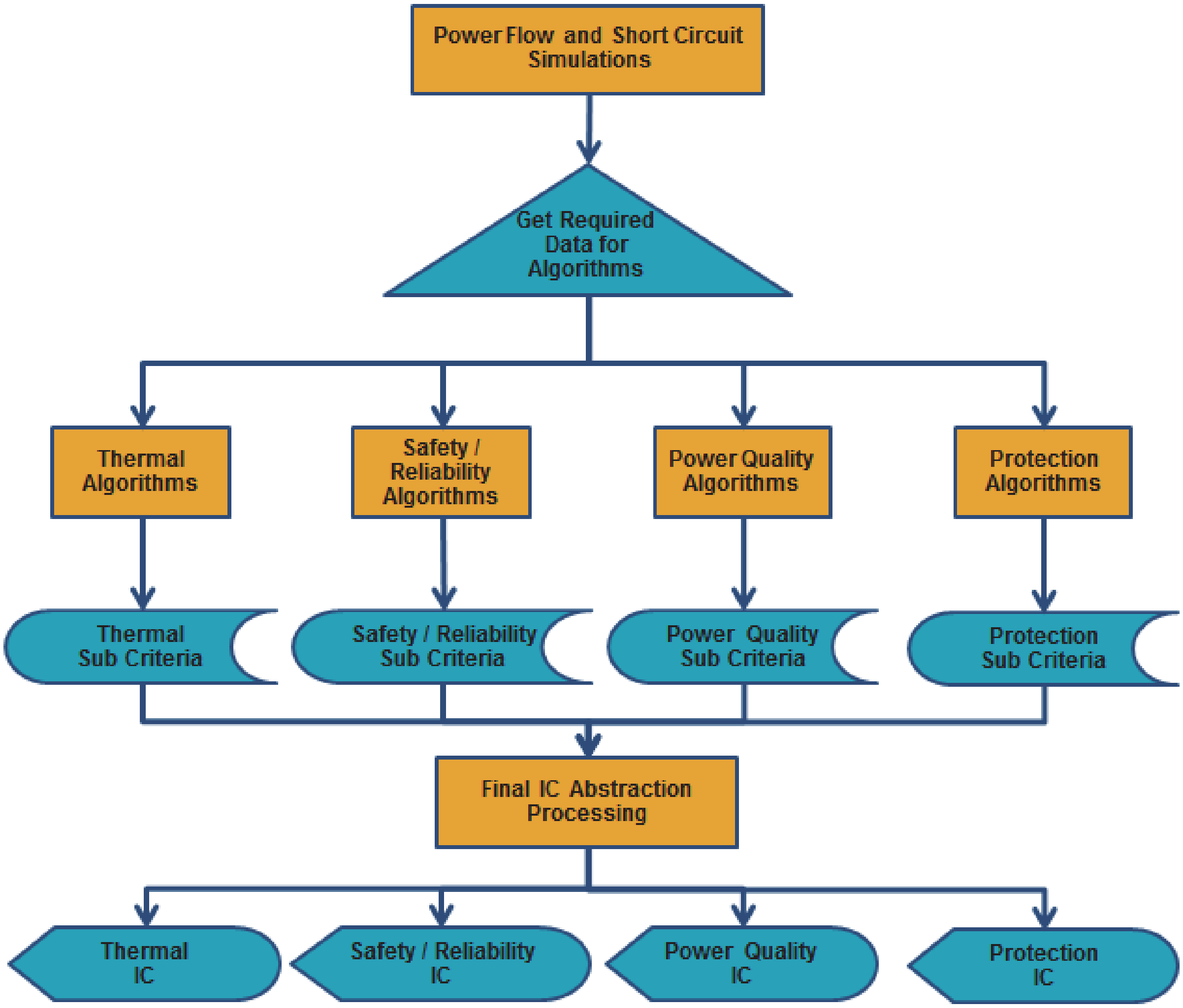

Figure 16: Streamlined Method Chart

Performing explicit calculations in abstraction enables a streamlined process that takes significantly less time than iterative processing which also lessens the IT resource needs. The following figure explains some of the abstraction processing that is also utilized with the full methodology. This is required to understand some of the hierarchy of the feeder and how upstream limitations affect specific node values. The code must be able to understand and manage the node and device network map to properly map these limitations.

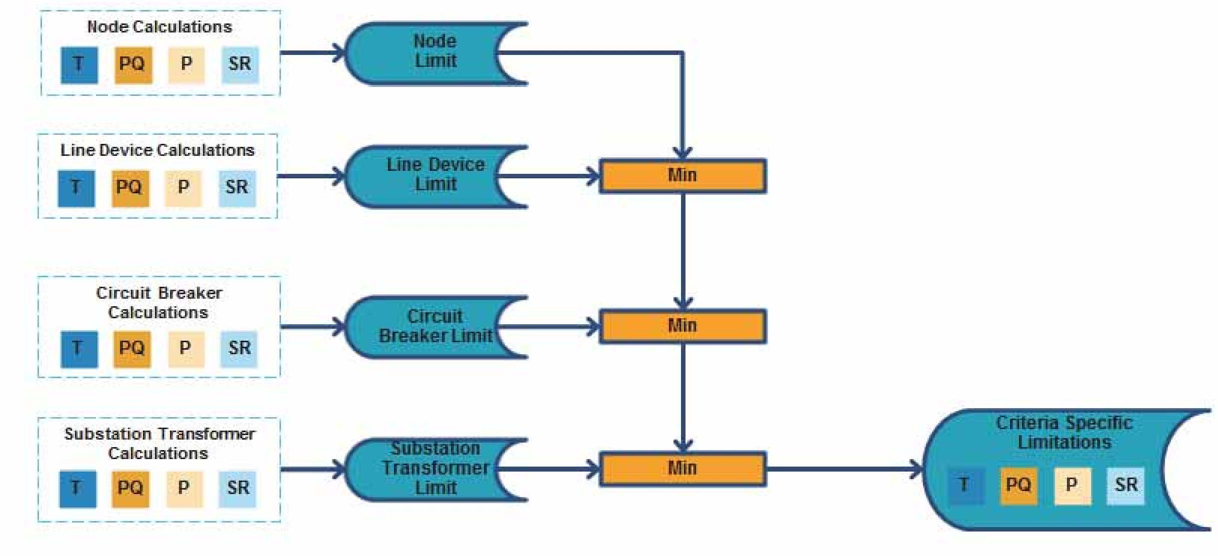

Figure 17: Layered Abstraction

Automated functionality was designed for LoadSEER to place desired load and forecast information into the model, extract the necessary data, and then perform the streamlined calculations. The python capabilities in CYMDIST were utilized for the power flow simulation, data extraction, and calculations.

4.d.i.2 Iterative Method

The iterative simulation is the direct modeling of new resources and performing iterative simulations for determining integration capacity at each node. Each analysis uses power flow calculation engines to compute the phase currents and voltages at every node on the network given the load and generation levels under various scenarios in the model. The iterative approach is consistent with engineering simulations performed on new interconnections during detailed studies. This method is expected to provide results that are expected to be more indicative of field conditions.

Figure 18 illustrates how each power system limitation criterion is evaluated though power flow or short circuit analyses and how the final ICA values are established based on the most limiting individual ICA values. This process will be repeated for every node of each feeder, and repeated for different power flow scenarios. During the reverse power flow scenario, the safety/reliability criterion (i.e., operational flexibility) will be excluded so that the study will allow reverse power flow.

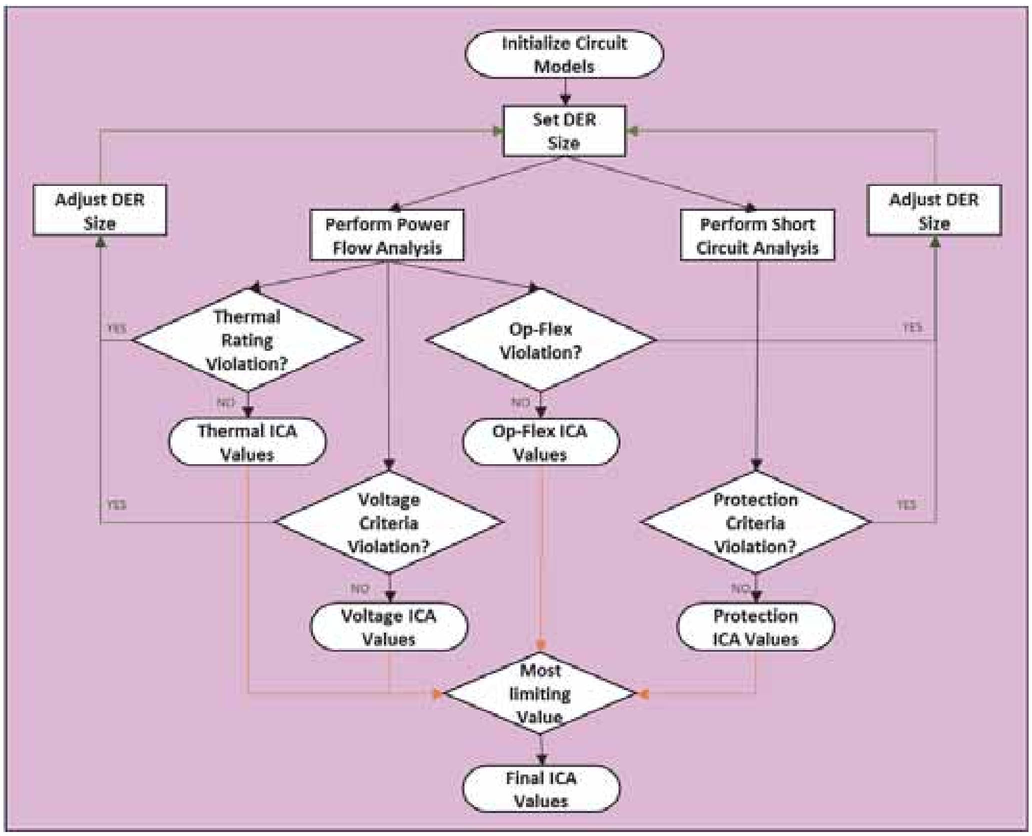

Figure 18: Iterative Method Flowchart

This approach allows for a greater amount of precision at the sacrifice of computational speed. Due to the precision of this approach, it is best suited for complex feeders where the streamlined approach may have difficulty in streamlining the dynamic voltage device operations on longer circuits.

PG&E coordinated with CYME during the duration of the demo. CYME has recently developed an ICA module within the CYMDIST tool. CYME's expertise in iterative calculations was appreciated and thus iterative techniques solely rely on the CYME ICA module.

4.d.i.3 Final Processing of Criteria Calculations

The analysis looks at various layers of the system. The final processing ensures that if there are limitations upstream that are dependent on downstream conditions (i.e. reduction of reach for a recloser) than all the downstream nodes are limited by that condition. This approach is more relevant for streamlined and blended approaches where analysis is more abstract and not always connected through the simulation as in the iterative approach. Figure 19 depicts the general process that is used to obtain the final set of results.

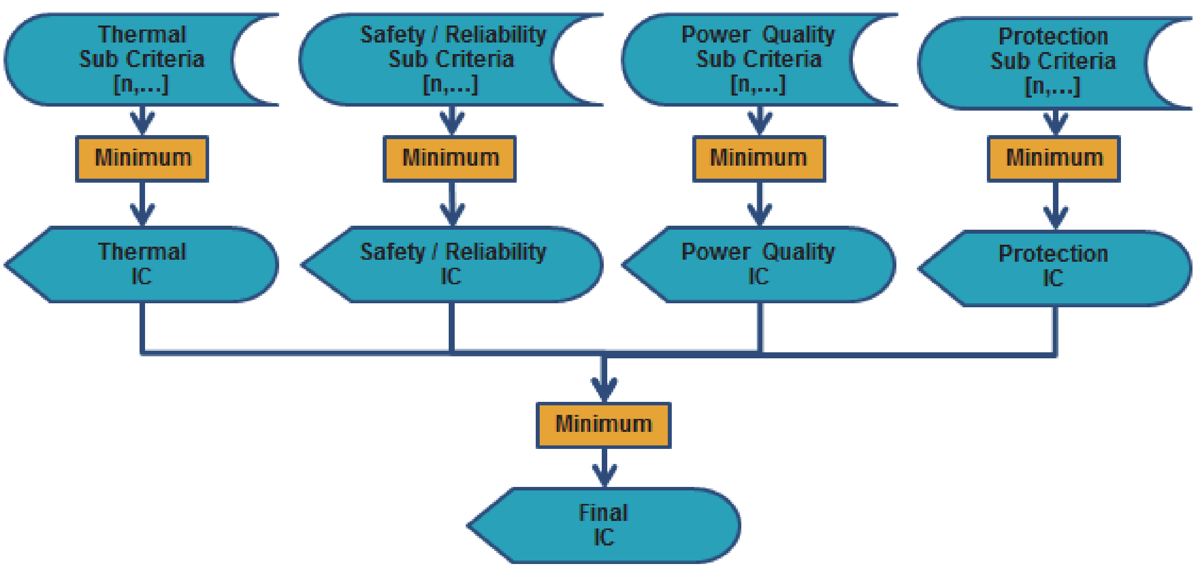

Figure 19: Final Processing of ICA Results

4.d.ii Thermal Criteria

Thermal criteria determine whether the addition of DER to the distribution feeder causes the power flow to exceed any equipment thermal ratings. These limits are the rated capacity of the conductor, transformer, cable, and line devices established by IOUs' engineering standards or equipment manufactures. Exceeding these limits would cause equipment to potentially be damaged or fail, therefore mitigation measures must be performed to alleviate the thermal overload.

An hour-by-hour calculation is performed to compare the equipment thermal limits given a certain amount of DERs. The Integration Capacity value is the highest value of DER which can be connected at a node which does not exceed the thermal rating of any piece of upstream equipment on the distribution circuit or substation.

The table below shows the equations and flags used to evaluate thermal limitations in the streamlined method and the iterative method, respectively.

Streamlined	$\text{kW Load Limit } [t] = \left(\text{Thermal Capability } - (\text{Load}[t] - \text{Generation } [t])\right)$ $\text{kW Generation Limit } [t] = \left(\text{Thermal Capability } + (\text{Load}[t] - \text{Generation } [t])\right)$
Iterative	• CYMDIST ICA Module: "Thermal Loading" • Power flow tool flags when abnormal loading conditions occur on the circuit.

In the equations, "kW Load Limit [t]" refers to the integration capacity value for energy consuming DERs at hour t; "kW Generation Limit [t]" refers to the integration capacity value for energy producing DERs at hour t; "Thermal Capability" refers to the 100% of the most limiting equipment's loading limit from the substation to the node being analyzed; "Load[t]" refers to gross load at hour t; "Generation[t]" refers to gross generation at hour t for the node being analyzed. The "Load [t] – Generation [t]" could be thought of or replaced by net load. Load and Generation may be stored and evaluated separately to help evaluate contingency scenarios which are not assessed at this time.

The iterative technique evaluates the loading conditions of all the assets on the feeder for each iteration of evaluation. When equipment thermal ratings are exceeded by their respective power throughput then the tool flags this condition. This condition then informs the ICA module that a thermal limit has been exceeded.

4.d.iii Power Quality / Voltage Criteria

Power Quality / Voltage Criteria determine whether the addition of DER to the distribution feeder causes the distribution primary feeder to operate outside of allowable power quality and voltage limits which can lead to customer facilities and equipment damaged. DER planning must include power quality analysis so that new resources are evaluated for sufficient voltage and quality of service.

There are both steady state voltage limits and voltage fluctuation limits established by IOUs' Rule 2 and Engineering Standards, which are drawn from American National Standard (ANSI) C84.1 - 2011 Range A.

Steady State Voltage

The table below shows the equation and flag used to evaluate steady state voltage limitations in the streamlined method and the iterative method, respectively.

Streamlined	$\text{kW Limit [t]} = \frac{\left(\text{Voltage Headroom [t] (per unit)} * V_{LL}{}^{2}\right)}{(R * PF_{DER} + X * \sin(\cos^{-1}(PF_{DER})))} * PF_{DER}$ $\mid \text{Voltage Headroom [t]} = \frac{\lvert\text{Rule 2 Limit} - \text{Node Voltage[t]}\rvert}{\text{Base Voltage}}$
Iterative	• CYMDIST ICA Module: "Abnormal Voltage" • Power flow tool flags for steady state over-voltage and under-voltage abnormal conditions

Steady state voltage changes can be generally estimated using the Ohm's Law principles. This limit is determined by the headroom of voltage from the simulated voltage at the node to the Rule 2 steady state voltage limits (i.e., the voltage shall remain in the range between 0.95pu and 1.05pu).

In the equation, "V_{LL}" refers to the actual circuit voltage at hour "t"; "R" and "X" refer to the line impedance to the node under study, "PF_{DER}" refers to the power factor of DERs, which is assumed at 1 in the study. Section 8.a evaluates smart inverters and DER operating at other power factors.

The iterative technique evaluates the voltage conditions of all the assets on the feeder for each iteration of evaluation. When abnormal voltage is observed outside of the prescribed ranges then the tool flags this condition. This condition then informs the ICA module that a thermal limit has been exceeded.

Voltage Variation

Voltage fluctuation is evaluated to ensure deviations from loads and resources on the grid do not cause harm or affect power quality to nearby customers. The voltage fluctuation limit used in Demo A is 3%[5], which is prescribed by engineering standard practices. This criterion is used in order to minimize the impact of fluctuations caused by DERs on other customers. The table below shows the equation used to evaluate voltage fluctuation limitations in the streamlined method.

Streamlined	$\text{kW Limit} = \frac{\left(\text{Deviation Threshold (per unit)} * V_{\text{LLnom}}{}^{2}\right)}{(R * PF_{DER} + X * \sin(\cos^{-1}(PF_{DER})))} * PF_{DER}$
Iterative	• CYMDIST ICA Module: “Voltage Variation” • Compare node voltages with DER on and off • Highest value recorded before deviation threshold is surpassed

The equation used for voltage fluctuations is fundamentally derived from Ohm’s law. In the equation, “Deviation Threshold” refers to the voltage fluctuation limit; “V_{LLnom}” refers to the nominal circuit voltage; “R” and “X” refer to the Thévenin impedance to the node under study, “PF_{DER}” refers to the power factor of DERs, which is assumed at 1 in the study. Section 8.a evaluates smart inverters and DER operating at other power factors.

Iterative methods perform a power flow with the DER on and off and compare the node voltages before and after. All voltage devices on the feeder are locked in order to understand the true voltage variation before the voltage devices correct for such changes. When any node voltage deviation surpasses the set threshold then the DER size is recorded for that node.

[5] The 3% limit can be found in IEEE Std 1453-2015 “IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems” in Table 3 for medium voltage systems.

Voltage Regulator Impact

Voltage regulators monitor specific conditions of the grid and dynamically adjust voltage based on changes to the system loading conditions. One of these conditions is monitoring current flows in order to estimate what the lowest voltage downstream would be. Historically the assumption was that current flow was always in the forward direction which assumes a voltage drop downstream. When DER is connected downstream from the regulator, with the current flow at the voltage regulator will reverse and the voltage rise due to the DER. If the regulator does not have the proper settings to understand this it will regulate the voltage improperly. Regulators now have options to consider the reverse flow conditions properly and manage the voltage while generation is downstream. When regulators do not have these settings and see reverse flow the analysis will flag for issues.

Streamlined	$\text{kW Limit } [t] = (\text{Load}[t] - \text{Generation } [t]) \mid \text{where limit} > 0$
Iterative	• CYMDIST ICA Module: "Reverse Flow" • Flag for reverse current through voltage regulator • Applied only to devices without distributed generation mode settings

The iterative method might not specifically need this screen if it models the regulating equipment operations. Currently the CYMDIST ICA module locks all regulating equipment in place. This means that the current form of iterative would not capture the full effect of reverse flow through voltage regulators. The ICA module also does not specifically separate reverse flow through different devices. Because of this, the regulator reverse flow was evaluated within the Operational Flexibility criteria for Demo A.

4.d.iv Protection Criteria

Protection Criteria determine whether the addition of DER to the distribution feeder reduces the ability of existing protection schemes to monitor the grid to promptly disconnect areas during abnormal system conditions (reduction of reach).

If a fault occurs electrically downstream of a distribution protection device, the device is designed to detect and interrupt high magnitude fault current as to isolate the affected portions of the circuit from the rest of the system. Typically, these devices are programed with defined Minimum Trip current settings so that the device does not open during normal peak loading conditions but can still detect the lowest fault current possible within its defined protection zone and trip quickly enough to safely isolate the affected system.

If a power producing DER is placed electrically downstream of the protection device, it is a source of power that can contribute to a fault and lower the fault contribution detected by upstream protection devices. The reduction of ability to detect a faulted condition is referred to as "reduction of reach." When DER causes significant reduction of reach the distribution protection device may not operate as designed when sufficient DER is connected beyond a protection device. DER planning must account for its impacts to protection schemes to keep employees, public, and assets safe from potential electrical disturbances on the distribution system.

The table below shows the equation and flag used to evaluate the reduction of reach limitations in the streamlined method and the iterative method, respectively.

Streamlined	$\text{kW Limit} = \frac{\text{Reduction Threshold Factor} * I_{\text{Fault Duty}} * \text{kV}_{\text{LL}} * \sqrt{3}}{\left(\frac{\text{Fault Current}_{\text{DER}}}{\text{Rated Current}_{\text{DER}}}\right)} * \text{PF}_{\text{DER}}$
Iterative	• CYMDIST ICA Module: "Protective Reduction of Reach" • Power flow tool flags for fault current lower than prescribed limits

The streamlined equation follows the screening concept that possible issues may arise when DER fault current reaches a certain percentage of fault duty. In this equation, "Reduction Threshold" refers to the threshold of DER contribution, which is 10% in the study, as specified in Rule 21; "$I_{\text{Fault Duty}}$" refers to the maximum fault duty current seen at each node; "kV_{LL}" refers to the circuit nominal voltage; "$\text{Fault Current}_{\text{DER}}/\text{Rated Current}_{\text{DER}}$" refer to DER fault current per unit contribution, which is assumed as 1.2 in the study for inverter based DERs[6].

The iterative method performs a fault flow analysis to the protection limitation. This determines the specific fault contribution that would occur based on the impedance between the fault and the generator and to ensure that the end of line fault current can still be seen. The device fault current must exceed the minimum trip value by a specific threshold as prescribed by protection engineering practices. A generator is placed at the end of line fault location for each protective zone and then simulates a fault at that node. When protection device currents do not meet set thresholds then the DER value is recorded.

4.d.v Safety / Reliability Criteria

[6] National Renewable Energy Laboratory, "Understanding Fault Characteristics of Inverter-Based Distributed Energy Resources", p.p.33

Safety and Reliability must also be analyzed as part of Integration Capacity. High penetration scenarios of DER have the potential to cause excess back flow that can result in congestion and affect reliability during system events. Safety and reliability is assessed to ensure that all customers are served reliably and safe under the abnormal operating conditions and high penetration scenarios that can occur on the electric grid.

Currently the Safety/Reliability Criteria is mainly assessed based on reverse flow at specific points on the system. There are some valid reasons when general reverse flow limitations are needed while some components of this criteria may be used in more heuristic senses. Two major instances of when reverse flow can directly trigger an issue is with voltage regulators protection devices. Voltage regulators may not be able to properly control the voltage given reverse flow conditions. There are even special controls that enable the handling of reverse power conditions. Protection devices can begin to provide false tripping if power flow is allowed to exceed the minimum trip settings of these devices. This would lead to false tripping and reduce reliability. PG&E strongly recommends to not discount reverse flow as a simple heuristic all together, but to understand when it should be appropriately applied.

One of the major components of these criteria is determining the ability to reliably serve portions of circuits in abnormal configurations. High DER penetration can potentially cause excess back flow and load masking which can result in poor reliability conditions during abnormal system configurations, circuit transfers and emergency restoration. When certain line sections are electrically isolated from the grid for repair or maintenance, other line sections are transferred to other grid source paths for continuous services to customers, the distribution system could be rearranged in a manner that unexpected power flows in a manner which would create safety and reliability concerns.

Operational Flexibility Limits

To ensure proper reliability during these abnormal system configurations, the Operational Flexibility Criteria aim to limit the amount of back feed through switching points which are generally SCADA controlled switching devices, so that when a line section is switched to a new configuration, the amount of generation on that section will only serve the local load and does not generate power through the tie point towards the alternative source. Similar to switching devices, backflow would also be limited to the amount of load beyond voltage regulating devices.

The Operational Flexibility Criteria ensures that the amount of energy producing DERs does not exceed the load beyond SCADA controlled switching devices; in other words, the criteria will match the generation to the load between an automated circuit tie and the adjacent SCADA controlled switching device on the feeder.

The table below shows the equation and flag used to evaluate the operational flexibility criteria in the streamlined method and the iterative method, respectively.

Streamlined	$\text{kW Limit}\,[\text{t}] = (\text{Load}[\text{t}] - \text{Generation}\,[\text{t}]) \mid \text{where limit} > 0$ $\mid \text{where device has SCADA capabilities}$
Iterative	• CYMDIST ICA Module: "Reverse Flow" • Power flow tool flags the reverse flow through selected devices such

	as switching devices, circuit breakers, remote automated reclosers, voltage regulators and remote controlled switches

The IOUs recognize that this is more of a heuristic approach. While heuristic approaches were not encouraged, the IOUs have established that non-heuristic approaches to analyzing this issue are quite process intensive and will significantly hinder the ability to achieve efficient results. In essence, this will not necessarily limit the amount of generation that can be placed on each substation, but disperse the allowable generation across all line sections connected to the substation. This can be an important aspect of reliability that needs to be addressed for high penetration scenarios of DER. Limitations in the iterative ICA module did not allow for the isolation and filtering of devices based on SCADA availability.

Transmission Penetration Limits

This limit is similar to operational flexibility, but specifically focused on the reverse flow through the substation transformers. This is mainly due to the fact that transmission limitations and conditions are not considered in the analysis. Similarly a good method to reduce possible unknown issues when conditions are unknown is to limit the back flow.

Streamlined	$\text{kW Limit }[t] = (\text{Load}[t] - \text{Generation }[t]) \mid \text{where limit} > 0$
Iterative	• CYMDIST ICA Module: “Reverse Flow” • Power flow tool flags the negative current through SCADA controlled switching devices such as remote automated reclosers and remote controlled switches • NOTE: This was not applied directly in ICA module and only applied

	in post process as substation simulation was not used.

If desire is to rely on ICA without this limitation, then PG&E strongly encourages a push to start advancing transmission level integration capacity. If not adopted when ICA plays a role in Rule 21 then doing so could have some major impacts to interconnection customers as well as lead to possible transmission issues.

The complexities of the data and limitation of assets in model required that this criterion be applied in post processing. The application of this specific criterion is not automated yet and will require more work to include in final automated processing.

Out of Phase Reclosing / Islanding

PG&E's Interconnection protection standards require that generators trip off in 2 seconds or less to ensure proper safety and reliability on the distribution system. Not doing so can create unsafe conditions and possible public harm or equipment damage when PG&E's protection devices reclose to restore line. Given the transient and complex nature of this criterion, the tools are not adequately setup to definitively determine the limit to which this will occur. Much research and evaluation has gone into establishing a set of criteria to ensure the proper safety margins are kept to not allow a possible unintentional island to occur. Currently the main condition that is of concern is when machine generation is present. This condition along with loading conditions establishes when certain mitigations must occur. PG&E follows its Distribution

Interconnection Handbook standard TD-2306B-002[7] on Distributed Generation Protection requirements to analyze this screen.

Due to new updates this this standard the application of this limit would be quite limited throughout the system. Along with inclusion of many other components for Demo A, it was decided to leave this out of scope for the demonstration.

7 https://www.pge.com/en_US/business/services/alternatives-to-pge/generate-your-own-power/distributed-generation/distribution-handbook.page

5 RESULTS

The following chapter is a discussion and presentation of some of the results obtained from the demonstration project.

5.a General Description

The demonstration project was supposed to analyze three types of scenarios:

1. ICA with and without Transmission Reverse Flow
2. ICA by Year (2017 and 2018)
3. ICA by DER Growth (Scenarios I and III)

The listed scenarios will help thinking of how ICA is used in planning. It will be important to consider how load growth and DER growth impact IC on circuits to properly account for future conditions.

The first scenario will analyze the impact of transmission reverse flow restrictions will have on ICA. The intent is to help determine what issues arise if reverse flow onto transmission is not necessarily considered an issue[8].

The second scenario analyzes how ICA would change overtime with new load growth. Sometimes new DER interconnects due to customers wanting to offset new load. Analyzing this dynamic can be useful to see if new load has an effect on IC.

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[8] PG&E can't guarantee no transmission issues with ICA at its current stage provided no transmission analysis is included in ICA for Demo A. PG&E believes this is a good screen to have until such analyses can be considered. This scenario was mainly included as a compliance item to meet requirements of the CPUC.

The third scenario analyzes how ICA would change with different growth scenarios. Same as how load growth may impact IC, DER growth could as well have a positive or negative impact that would be good to understand for planning scenarios.

The following sections present visualized results across the result set in order to obtain some higher level insights from the data. Section 5.b evaluates all the feeders for the three main scenarios listed above. Section 5.c deep dives into results across four feeders. This section was narrowed to four feeders as the ability to process more detailed results across many feeders is very difficult and in general can be duplicative for determining general findings.

5.b Representative ICA Results (Analysis Scenarios)

The results were evaluated across different dimensions to help frame for various questions. These first few figures help visualize the results in a very high level aggregate sense. Many utilize box plots in order to gauge the range of ICA results across all the nodes and hours of simulation.

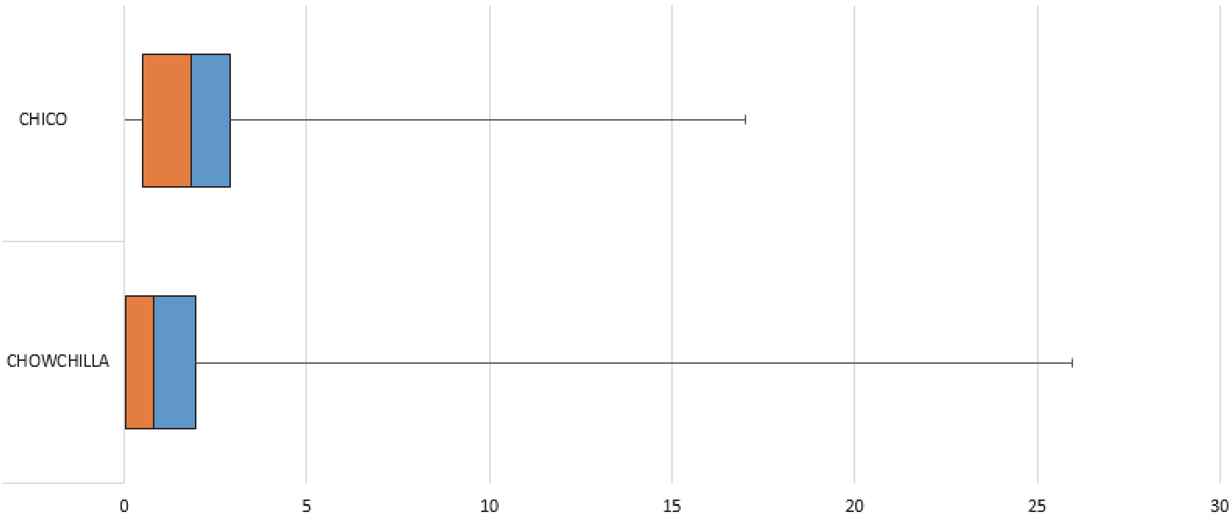

Figure 20: Box Plot of Gen IC (MW) Node Results for each DPA

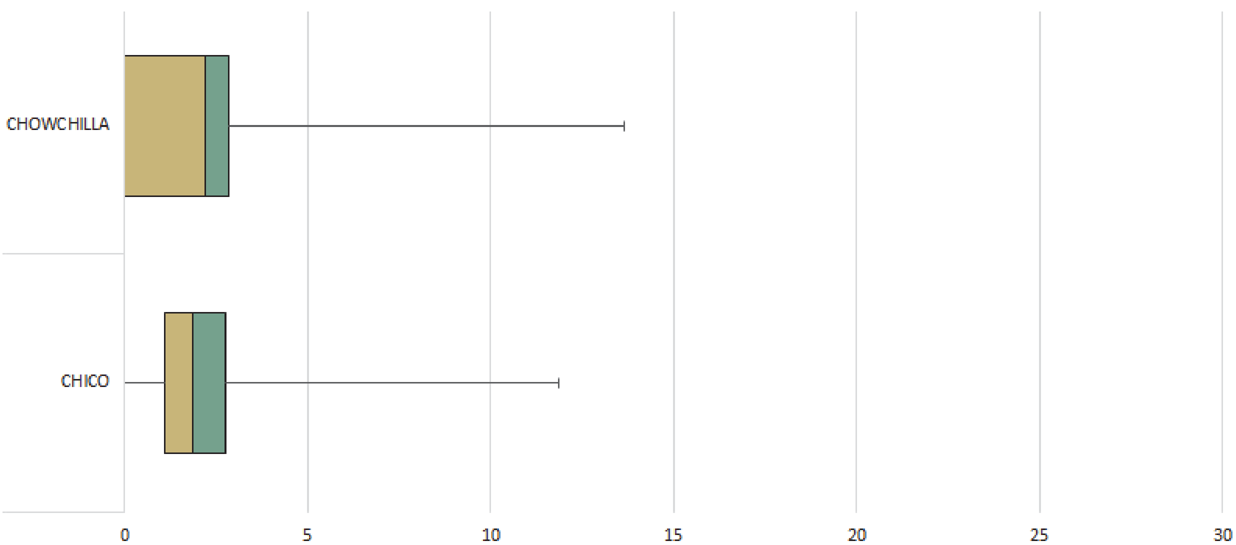

Figure 21: Box Plot of Load IC (MW) Node Results for each DPA

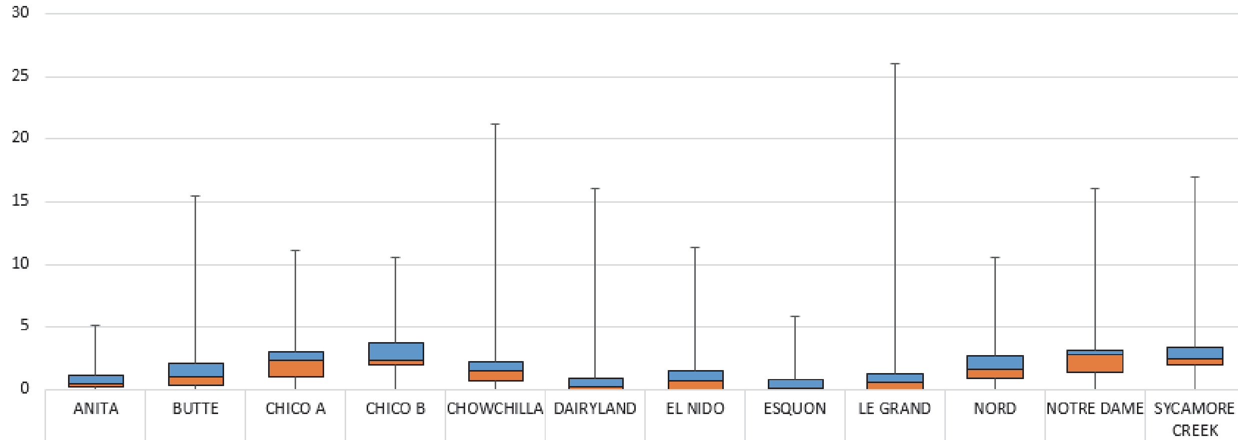

Figure 22: Box Plot of Node Gen IC (MW) for each Sub

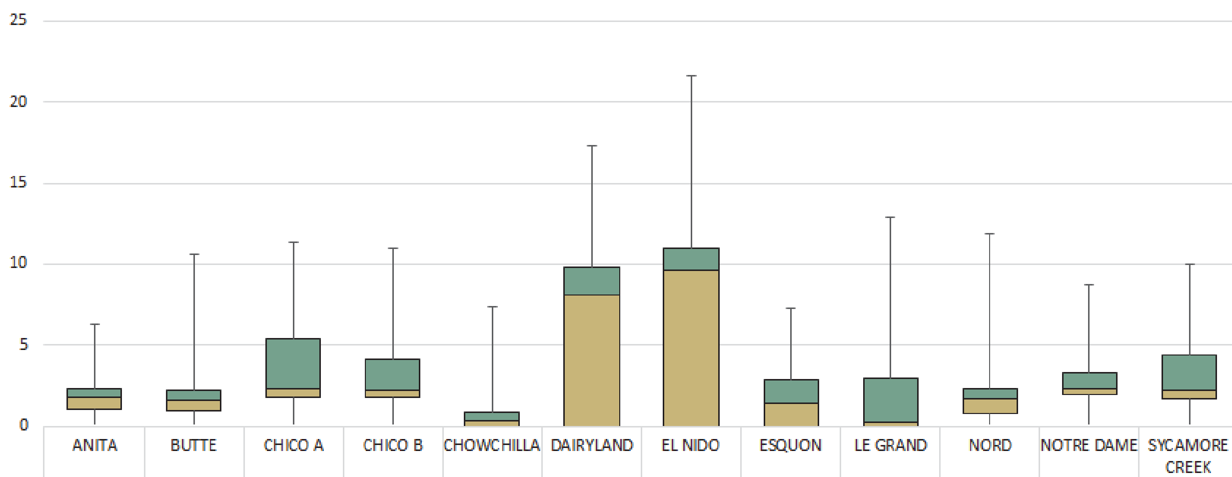

Figure 23: Box Plot of Node Load IC (MW) for each Sub

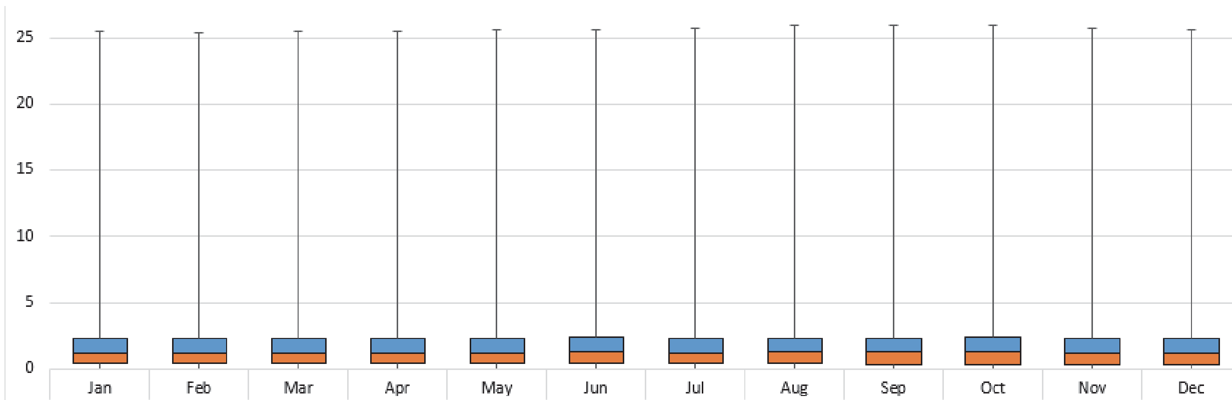

Figure 24: Box Plot of Node Gen IC (MW) for each Month

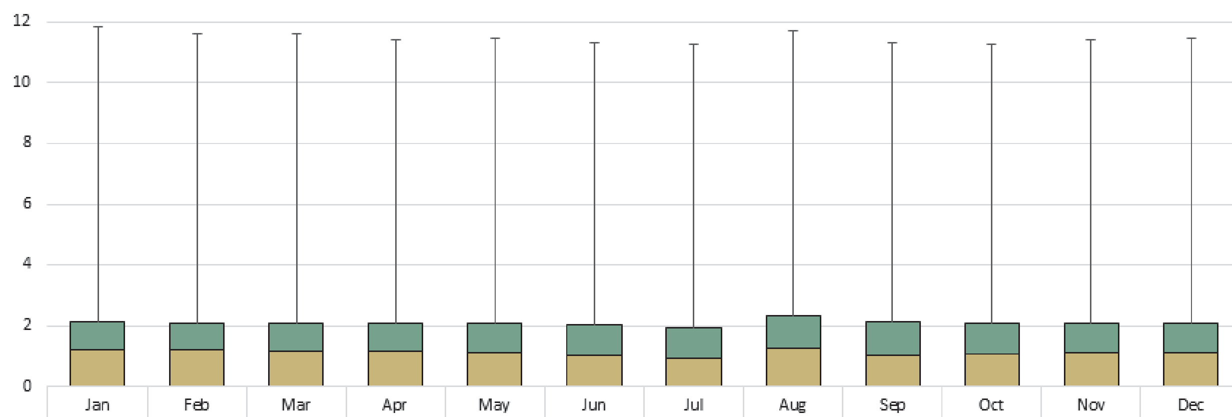

Figure 25: Box Plot of Node Load IC (MW) for each Month

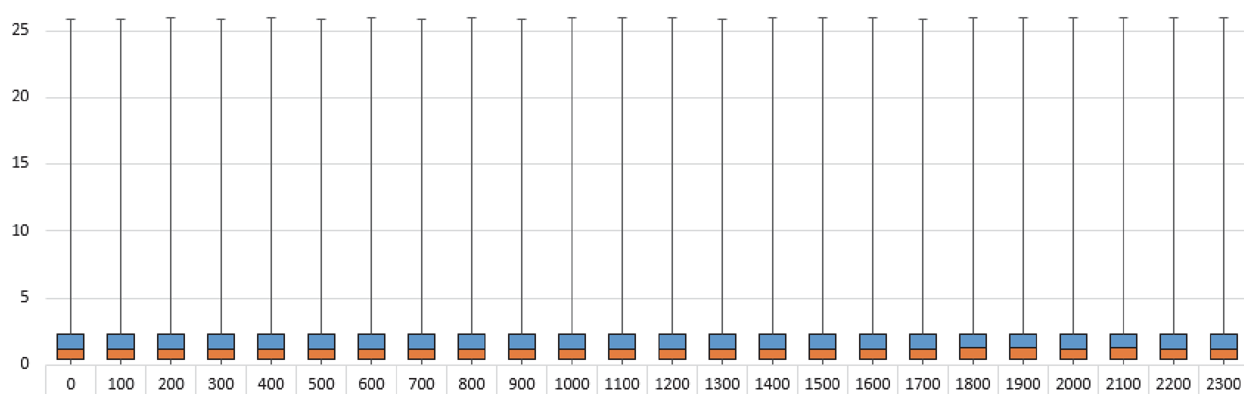

Figure 26: Box Plot of Node Gen IC (MW) for each Hour

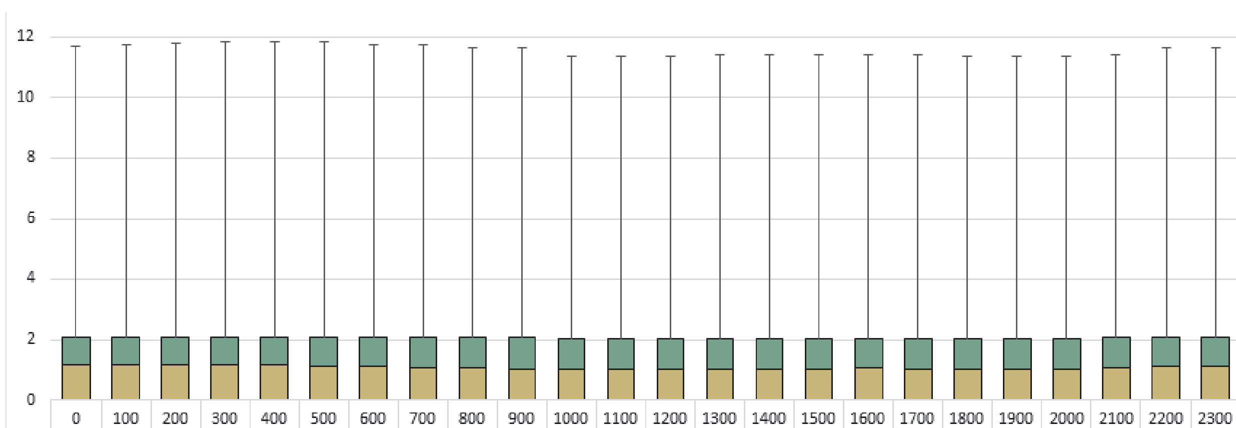

Figure 27: Box Plot of Node Load IC (MW) for each Hour

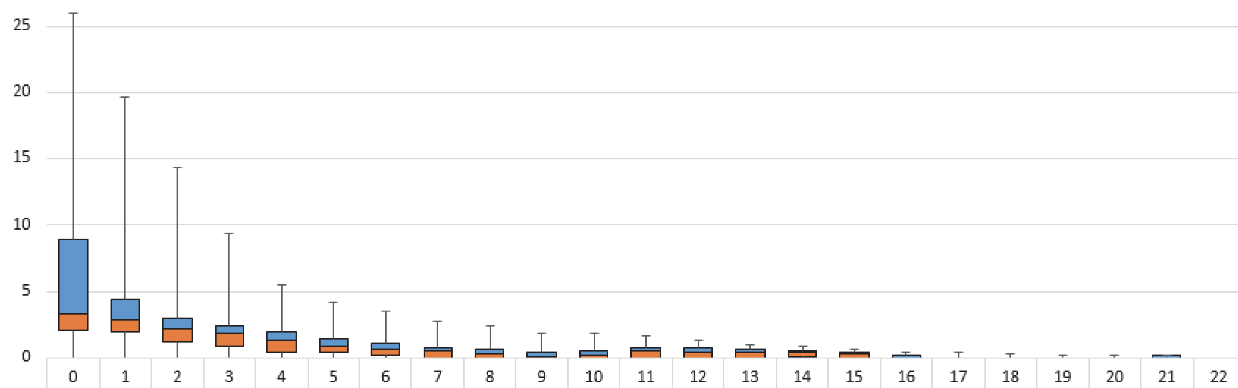

Figure 28: Box Plot of Node Gen IC (MW) for each Distance from Sub Bin (mi)

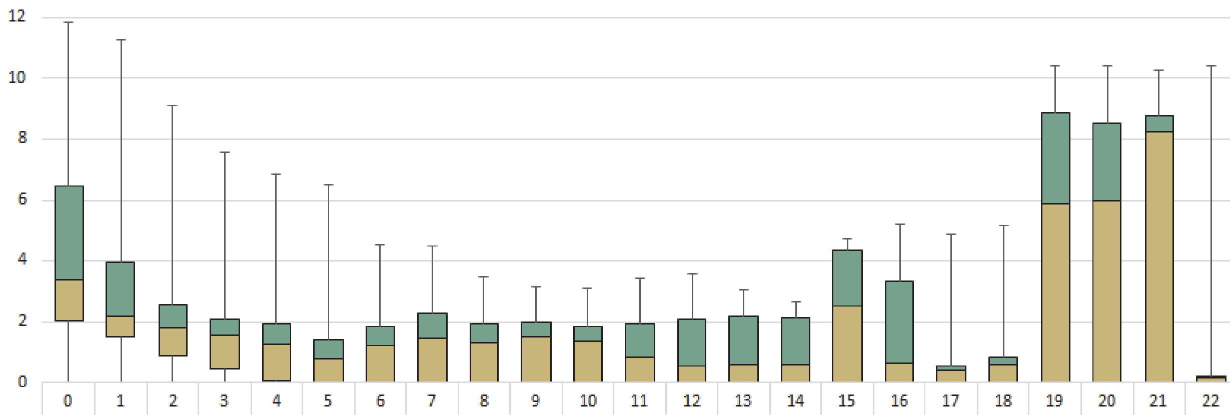

Figure 29: Box Plot of Node Load IC (MW) for each Distance from Sub Bin (mi)

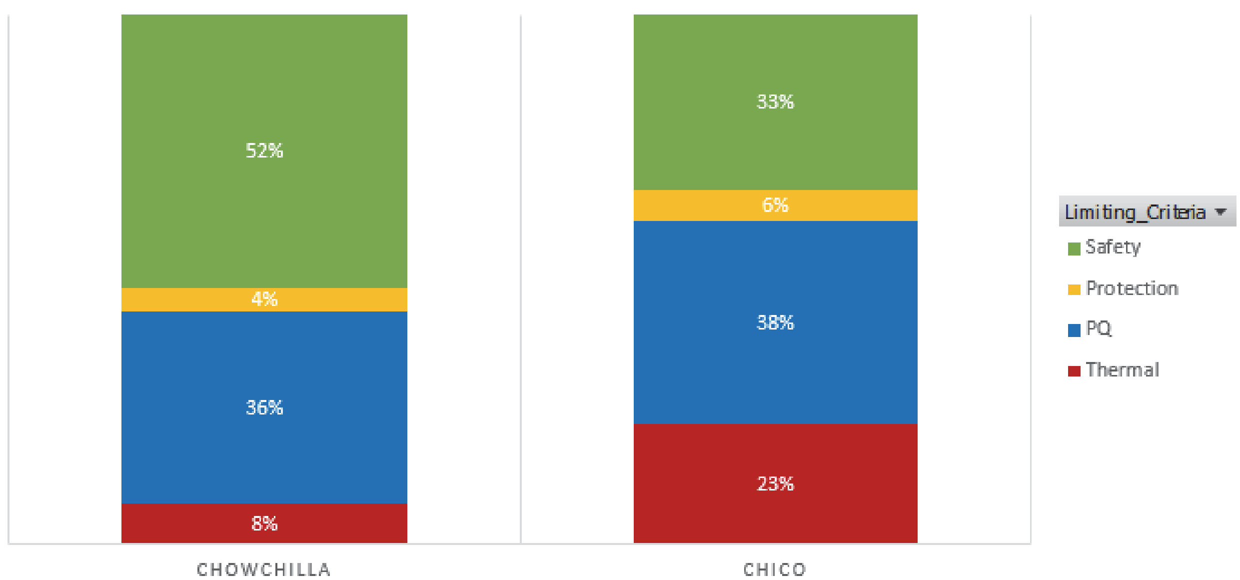

Figure 30: Percentage Share of Gen IC Limiting Criteria within each DPA

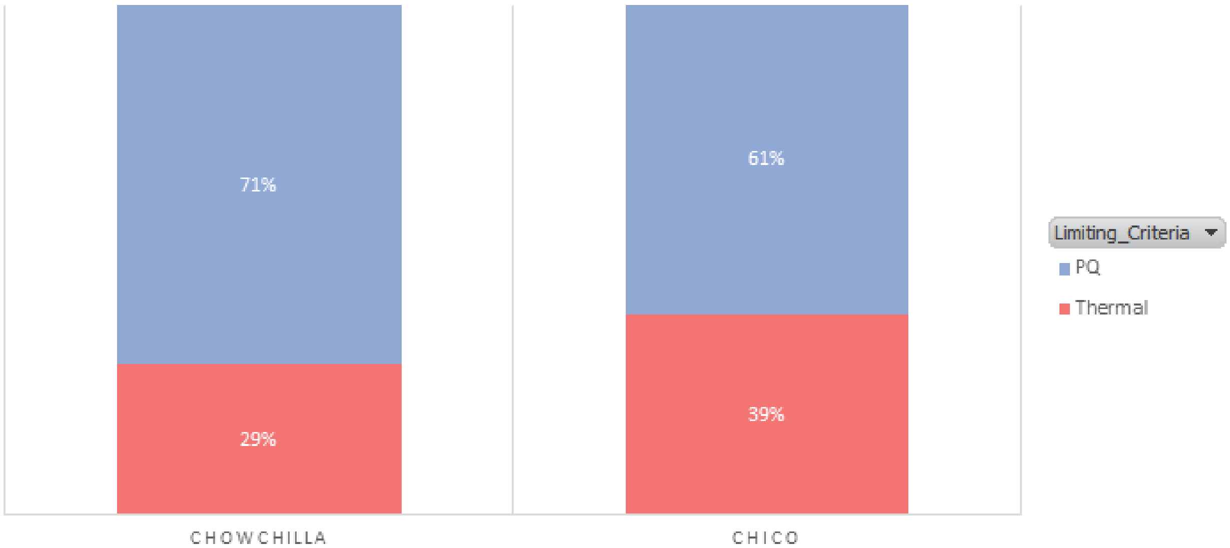

Figure 31: Percentage Share of Load IC Limiting Criteria within each DPA

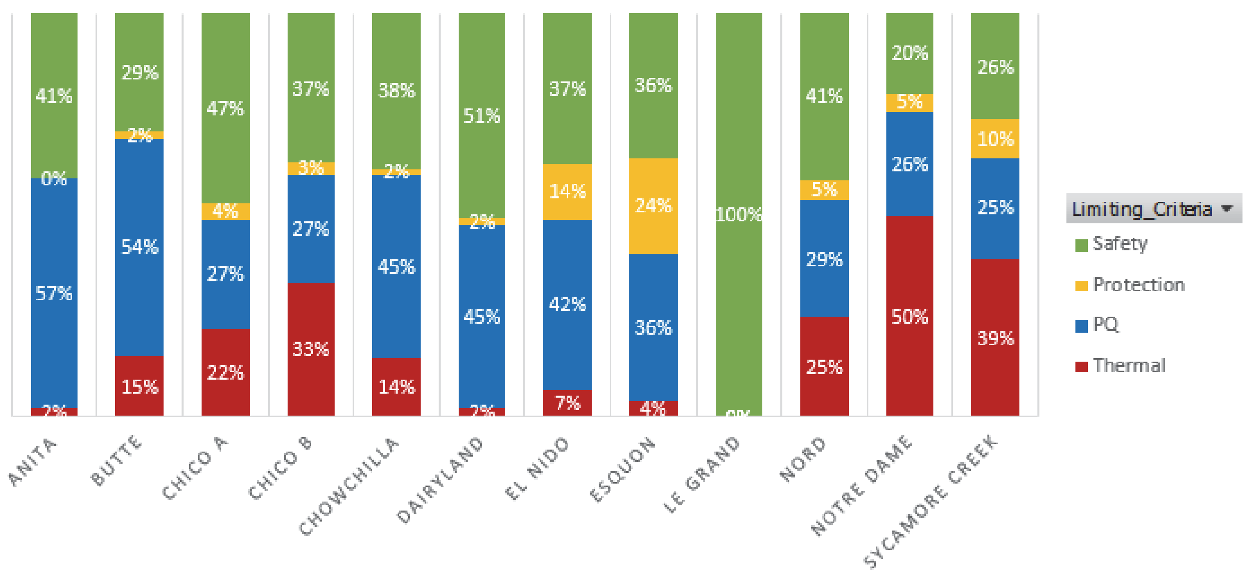

Figure 32: Percentage Share of Gen IC Limiting Criteria within each Sub

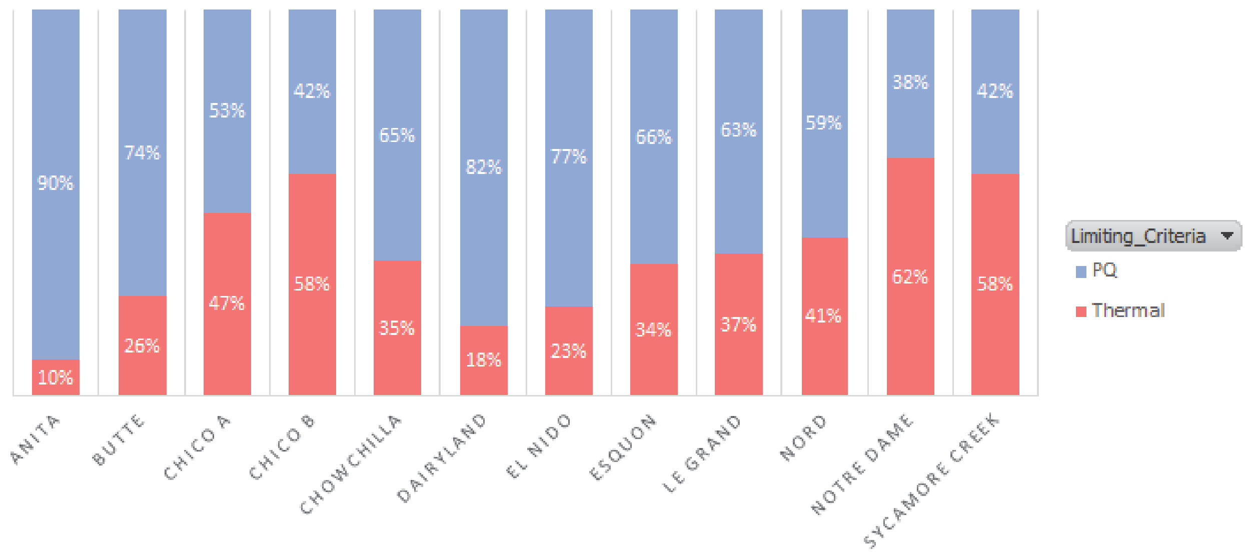

Figure 33: Percentage Share of Load IC Limiting Criteria within each Sub

1) ICA with and without Transmission Reverse Flow

The demonstration was tasked with understanding how IC changes when reverse flow restrictions are not a constraint in the analysis. To analyze this, the Final ICA was considered with and without the Safety criteria. The two numbers were then analyzed to see what the increase was after taking away the reverse flow restriction.

The figures below help depict the range of IC increases that occur in the feeders with box plots of all the node specific values. It can be seen with these charts that there can be some significant increases in certain areas. However, the box plot analysis shows that the majority of the nodes may show about a 1-2MW increase if not much at all.

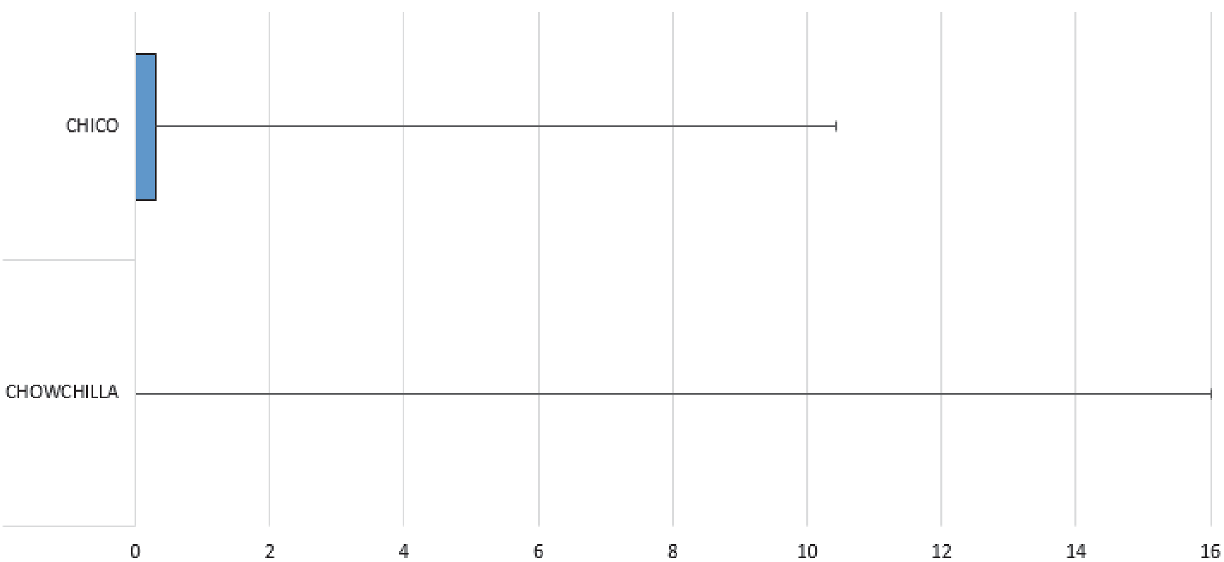

Figure 34: ICA Increase by DPA Allowing Reverse Flow

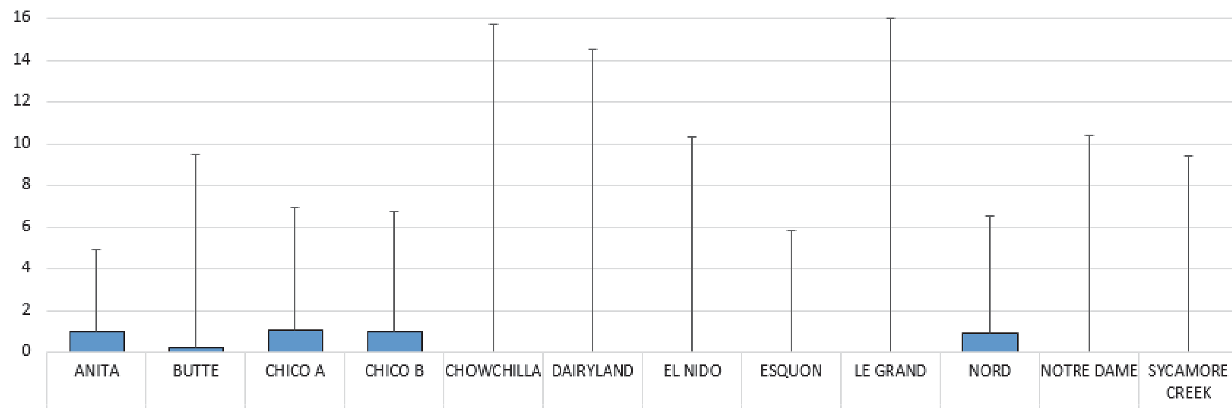

Figure 35: ICA Increase by Sub Allowing Reverse Flow

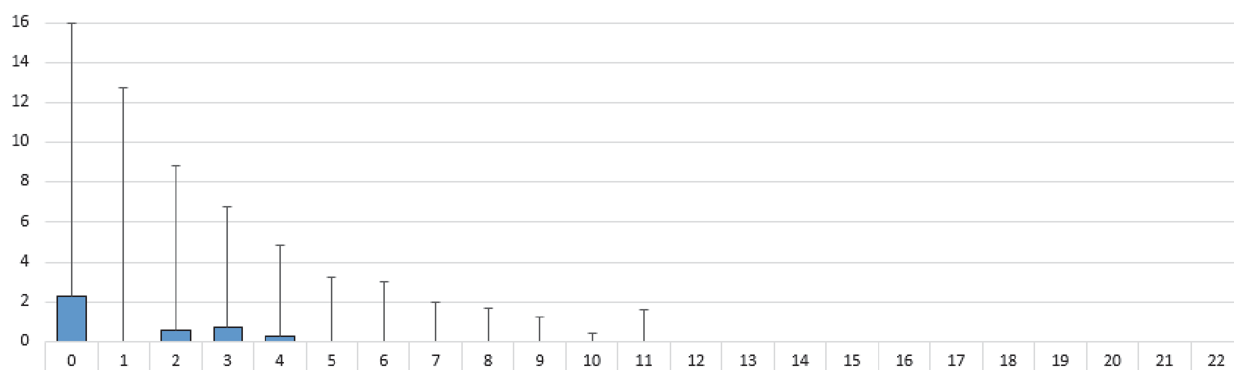

Figure 36: ICA Increase by Distance Allowing Reverse Flow

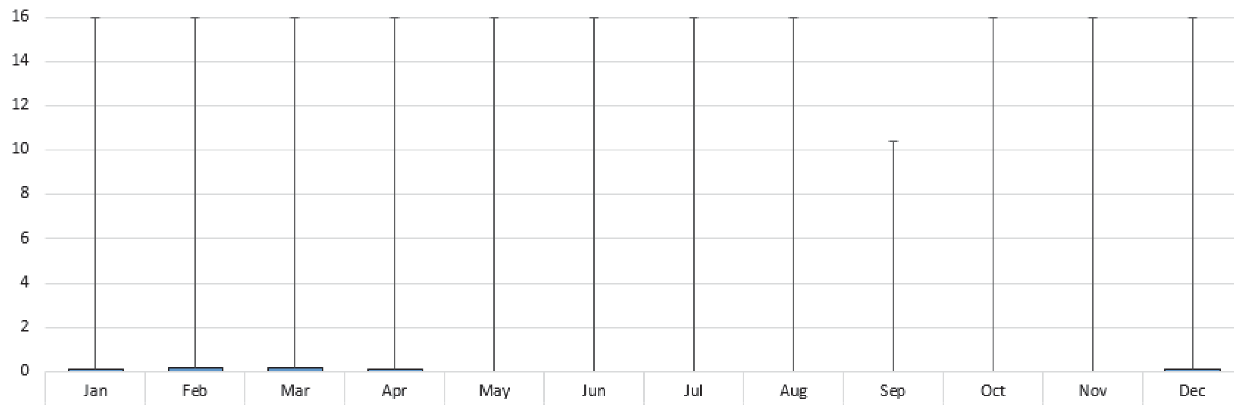

Figure 37: ICA Increase by Month Allowing Reverse Flow

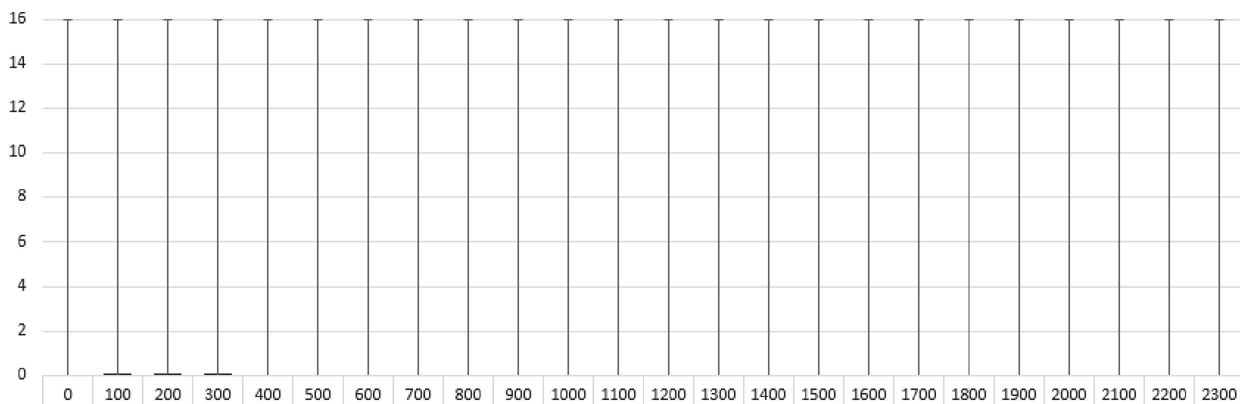

Figure 38: ICA Increase by Hour Allowing Reverse Flow

2) ICA by Year (2017 and 2018)

The demonstration was asked to determine the ICA analyzed on the forecast data for the year 2018. The assessment just focuses on gen ICA for ease of discussion. While there may be specific points on the circuit that get affected by the growth, there is not much difference due to the growth in these areas when assessing in aggregate. The majority of the data points have insignificant changes that have the main quartile ranges near zero.

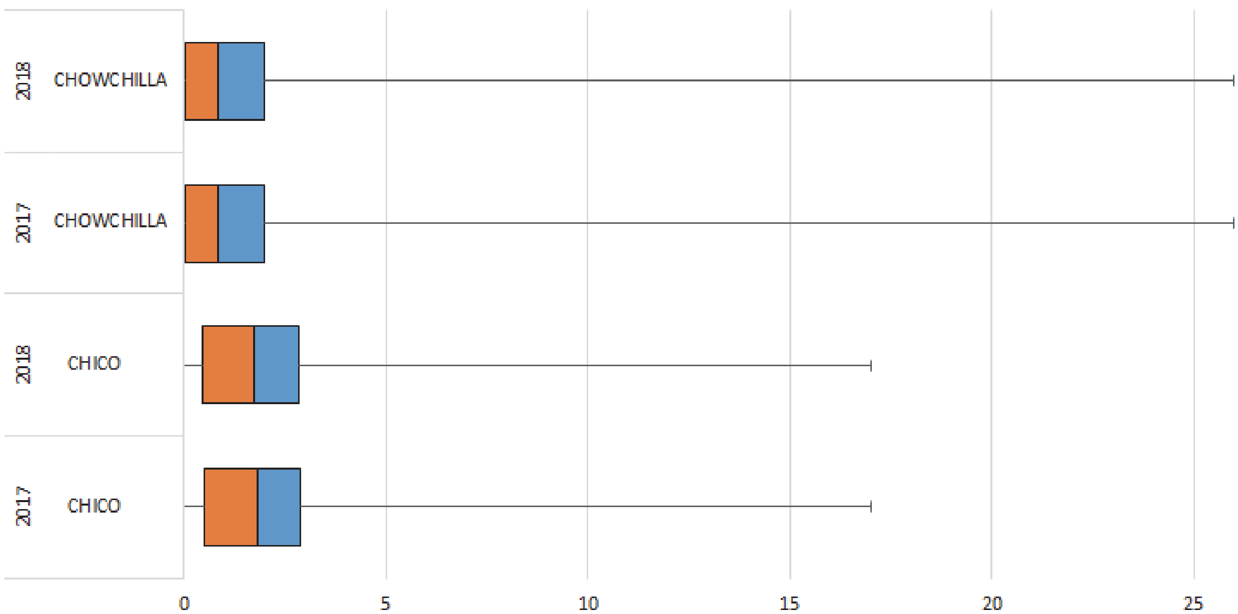

Figure 39: ICA Value Range by Year and DPA

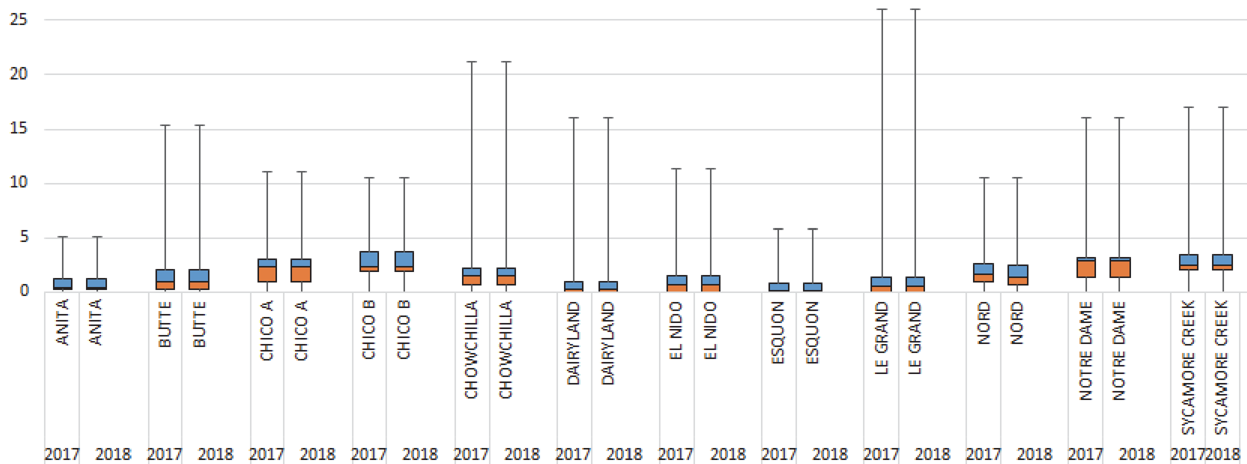

Figure 40: ICA Value Range by Year and Sub

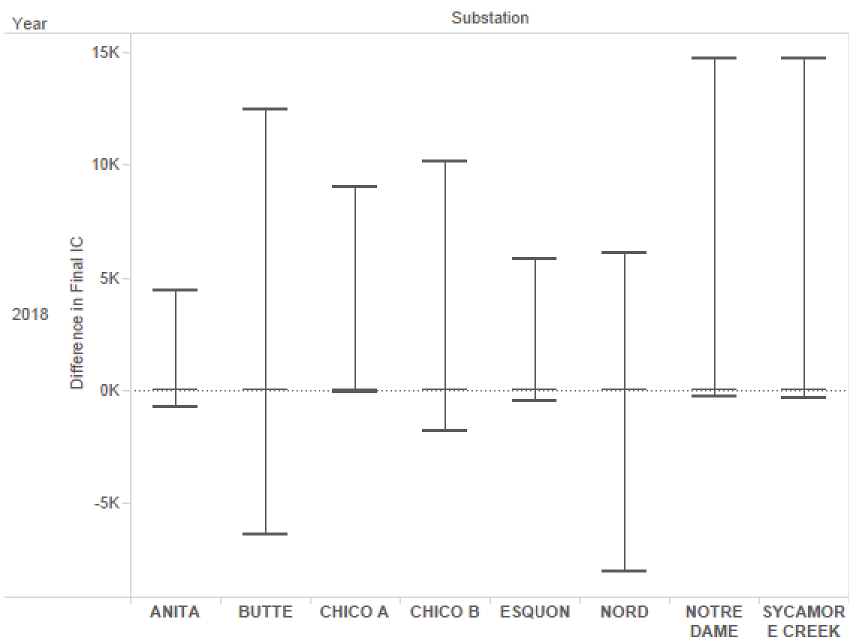

Figure 41: ICA Increase Box Plots for Chico by Substation in 2018

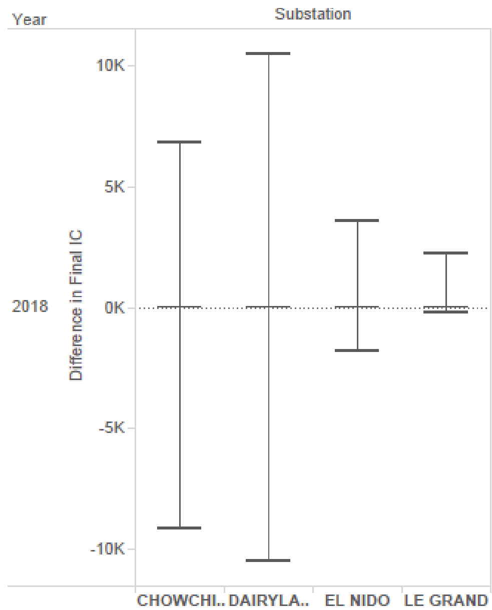

Figure 42: ICA Increase Box Plots for Chowchilla by Substation in 2018

3) ICA by DER Growth (Scenarios I and III)

The demonstration was asked to determine the ICA analyzed on the forecast data for the DER growth scenarios. There are some locations and nods within the set that ranges from big increases to big decreases. For the majority of the data points, that aren' t insignificant, there seems to be a decrease in IC with the larger growth scenario.

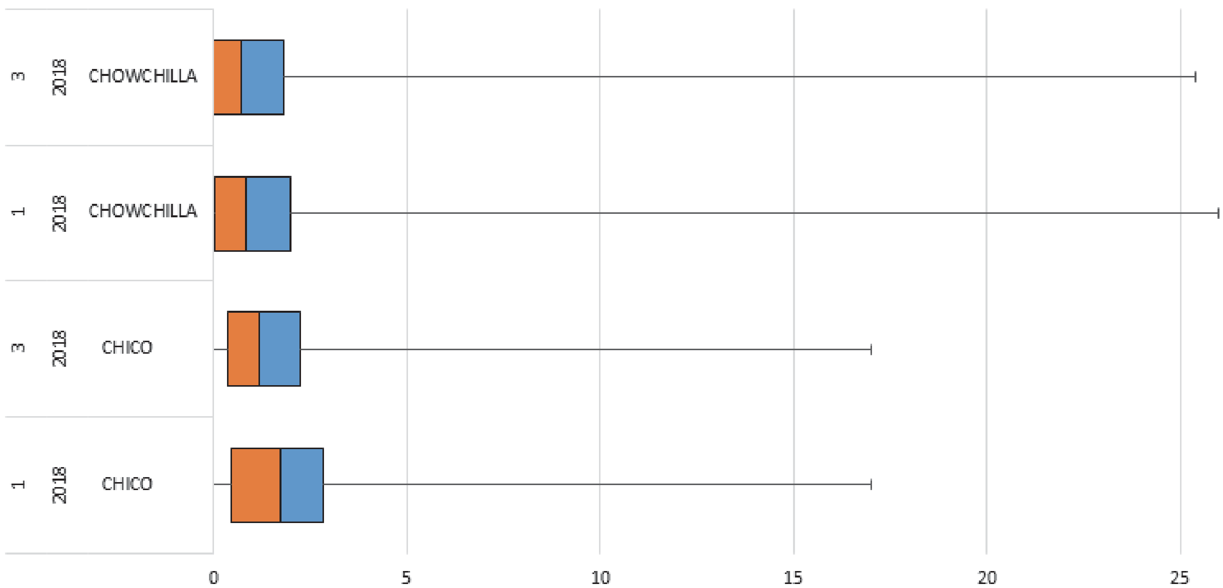

Figure 43: ICA Value Range in 2018 by Growth Scenario and DPA

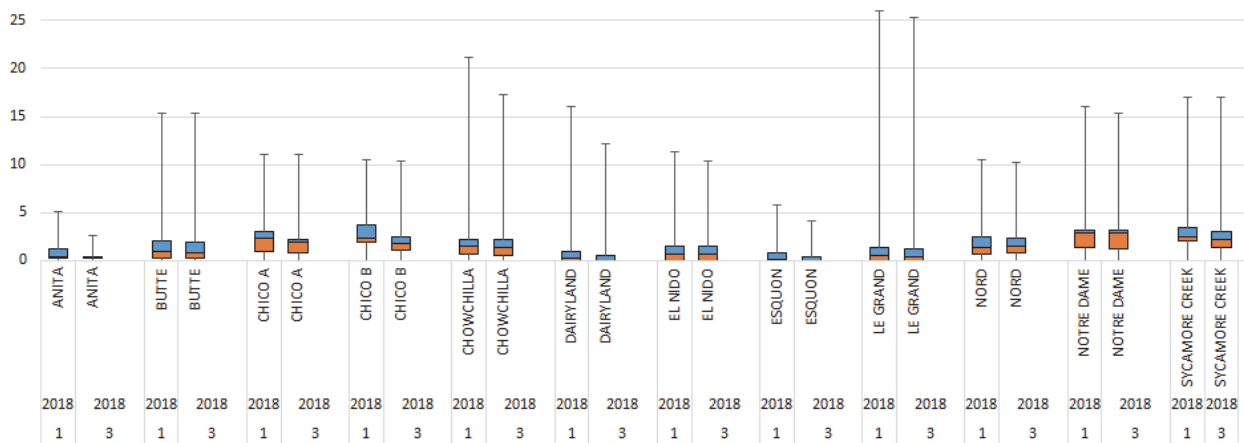

Figure 44: ICA Value Range in 2018 by Growth Scenario and Sub

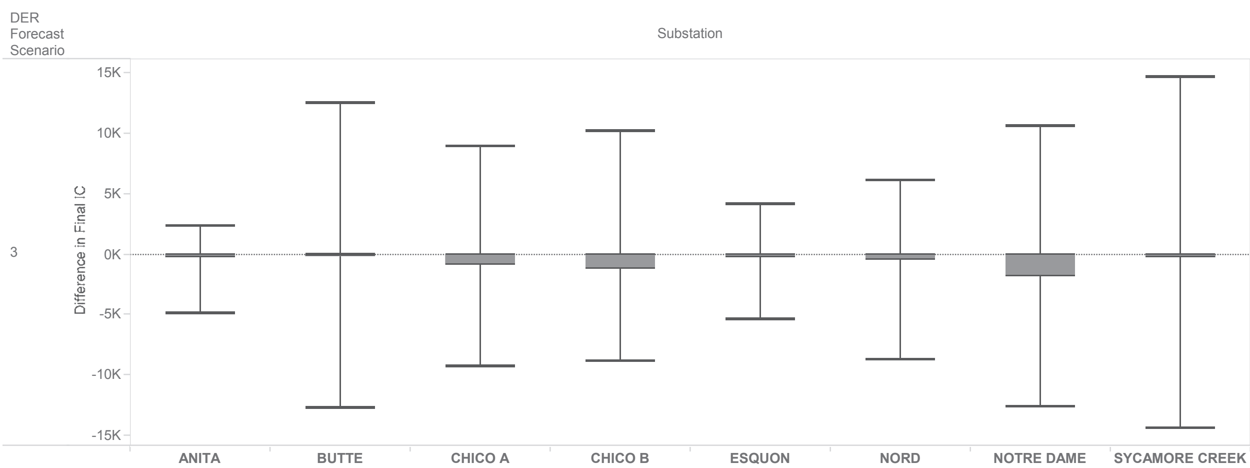

Figure 45: ICA Increase Range by Sub in 2018 for Chico from Growth Scenario 1 to 3

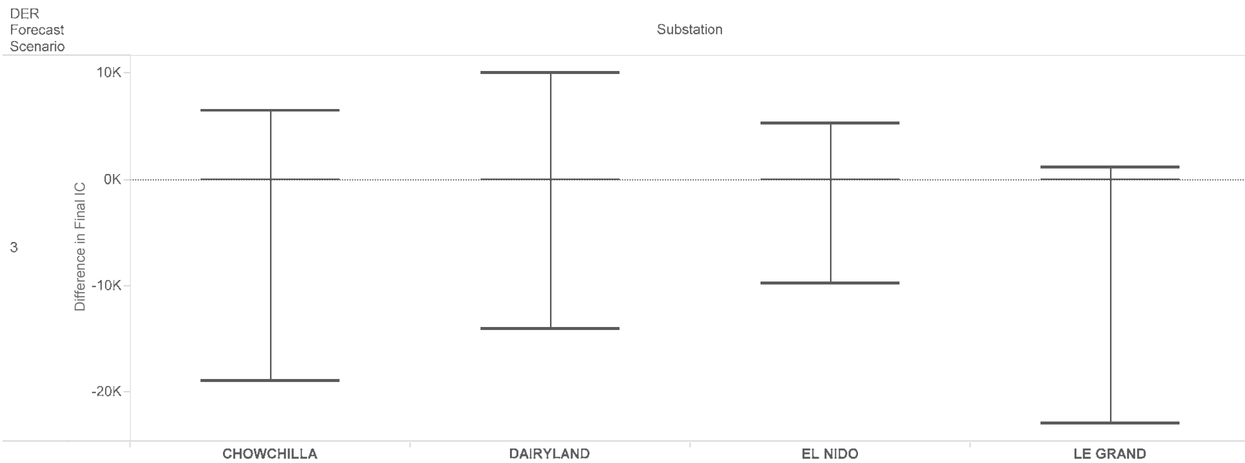

Figure 46: ICA Increase Range by Sub in 2018 for Chowchilla from Growth Scenario 1 to 3

5.c Representative ICA Results (Deep Dive)

As mentioned this section is a deep dive summarizing results for four specific feeders. Two feeders from each DPA were chosen with one being shorter and the other longer in distance from substation.

Limiting Criteria

The following is a deep dive into the assessment of the limiting criteria across the node results.

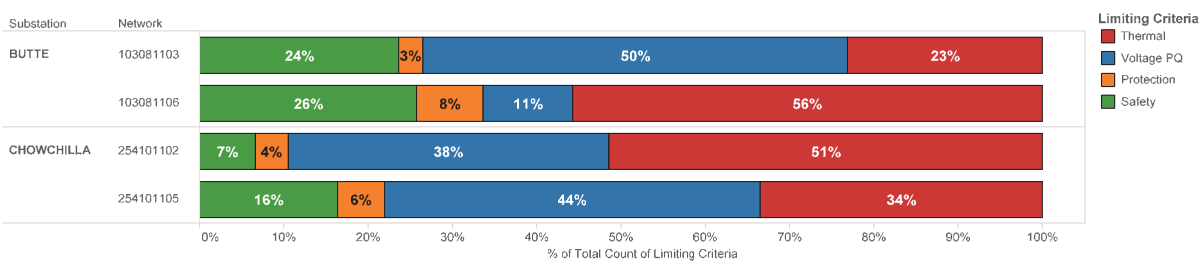

Figure 47: Summary of Limiting Criteria Percentage Share by Feeder

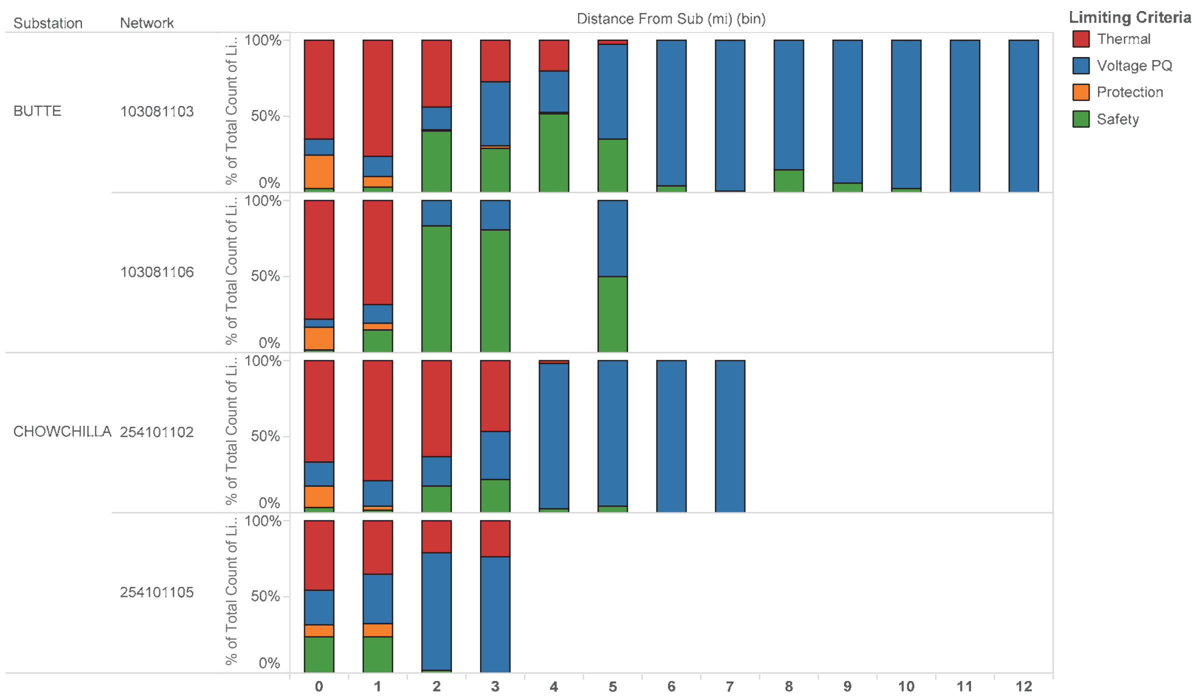

Figure 48: Limiting Criteria Percentage Share for each Bin of Mile from Sub

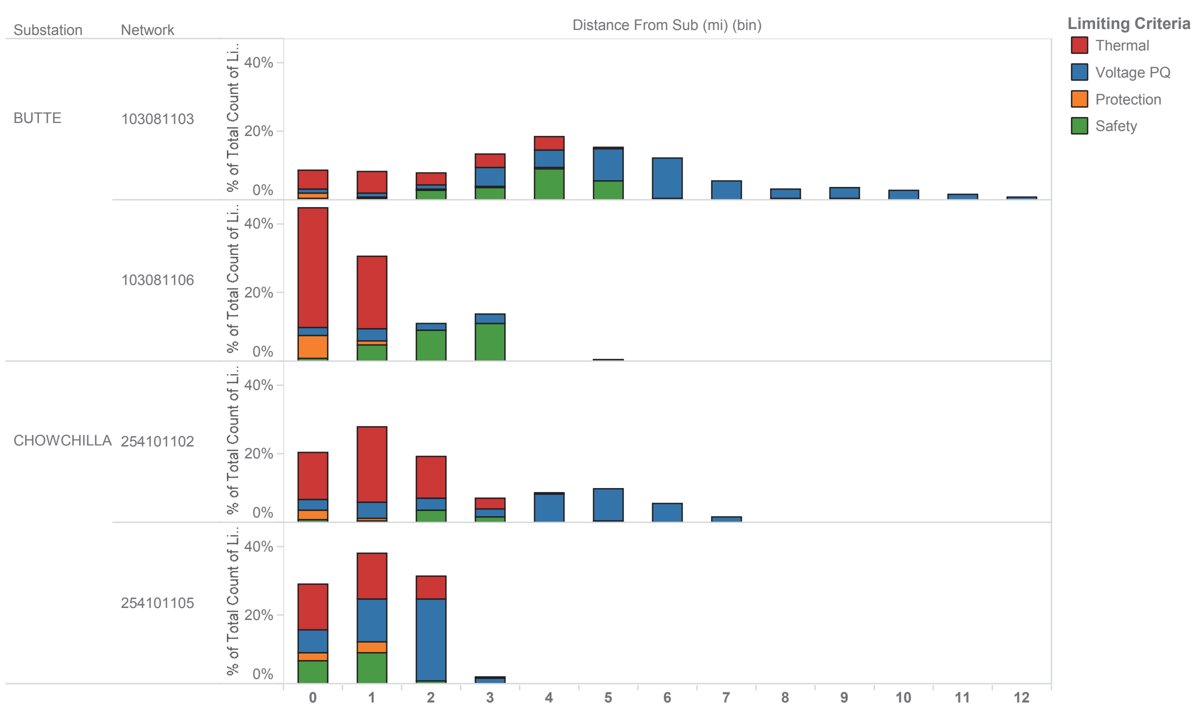

Figure 49: Limiting Criteria Percentage Share for Feeder across the Bins of Mile from Sub

Note that Figure 49 is the same as Figure 48 except that in Figure 49 the percentage share is calculated across the whole feeder versus additionally for each distance bin.

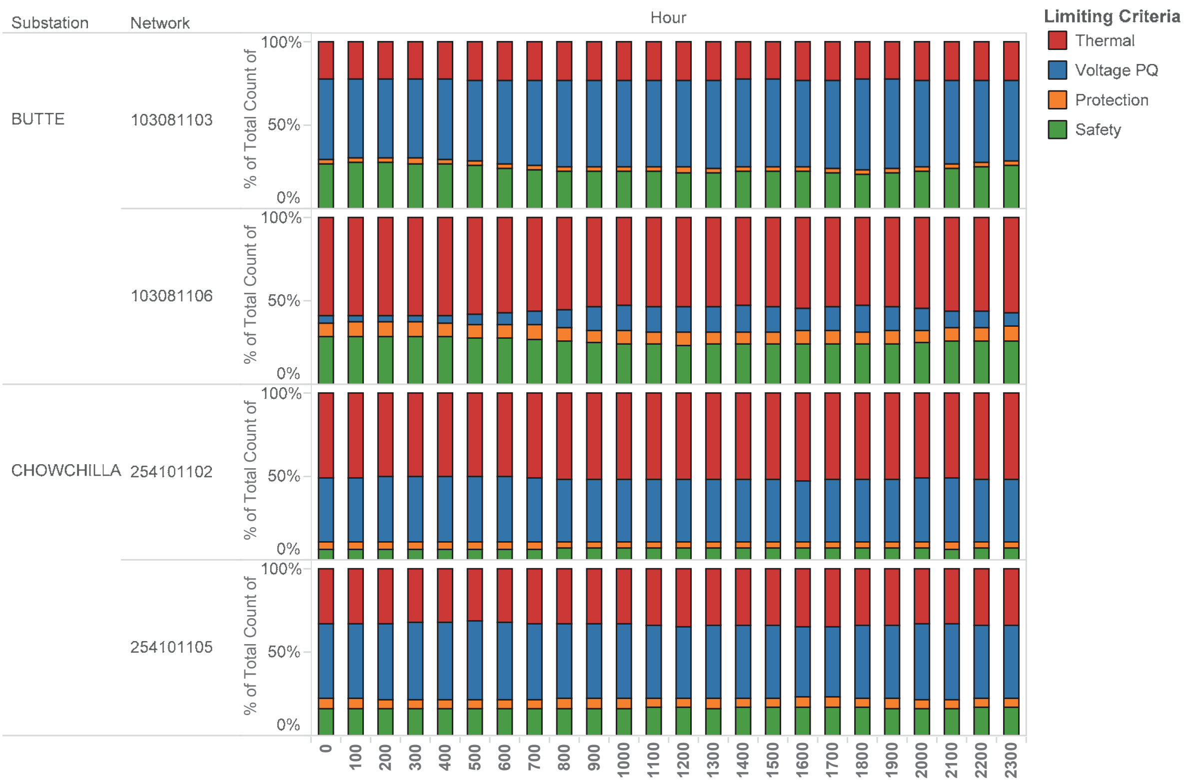

Figure 50: Limiting Criteria Percentage Share for Each Hour

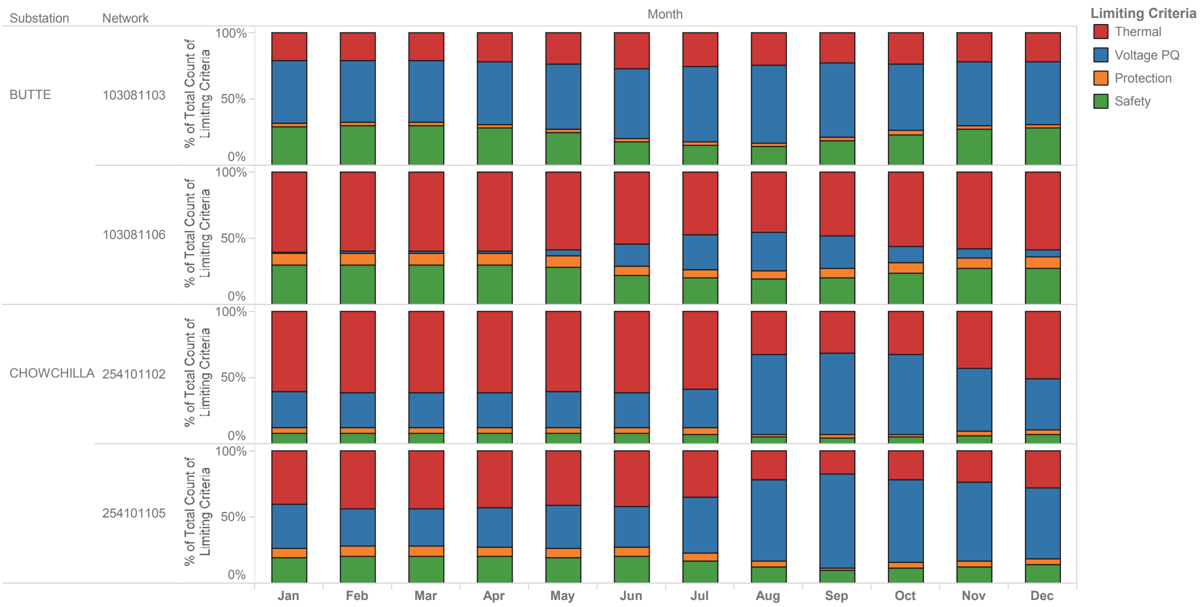

Figure 51: Limiting Criteria Percentage Share for Each Month

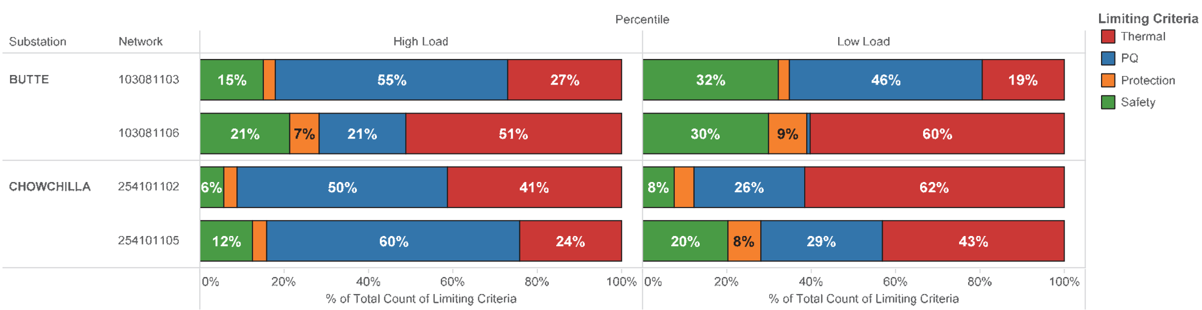

Figure 52: Limiting Criteria Percentage Share for Each Loading Condition

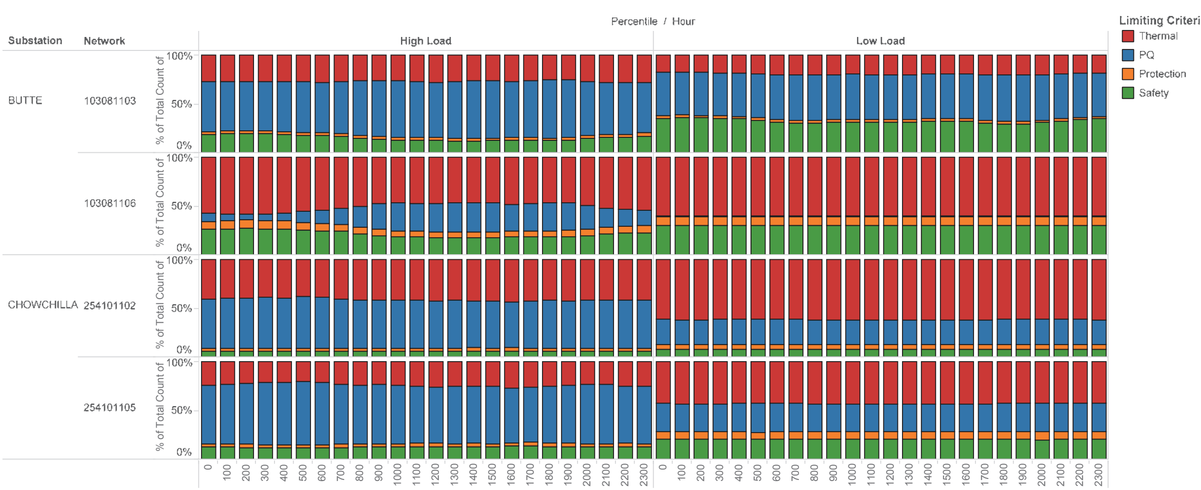

Figure 53: Limiting Criteria Percentage Share for Each Loading Condition and Hour

ICA across Distance

The following two figures show each node ICA by distance across feeders.

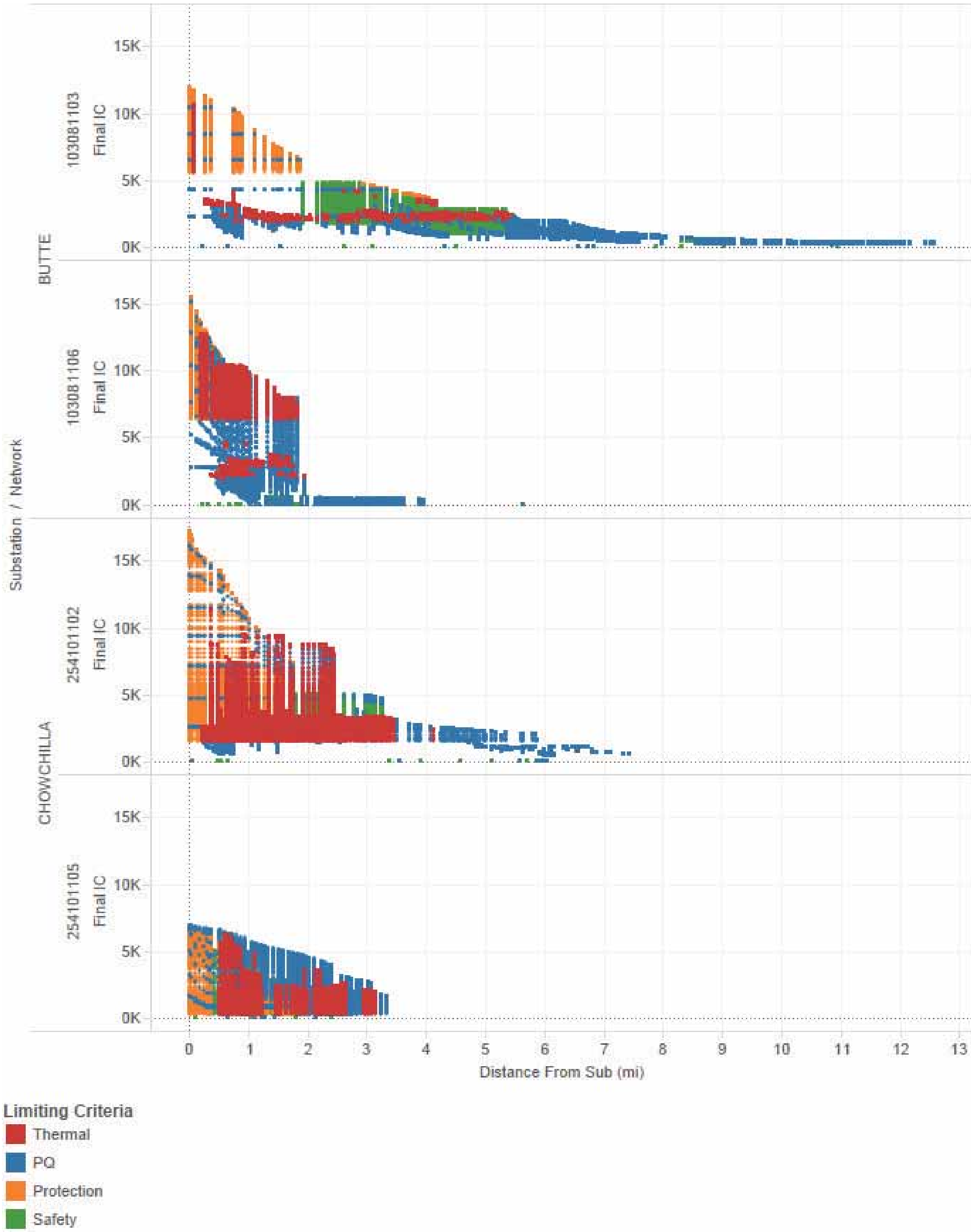

Figure 54: Final IC over Distance Colored by Limiting Criteria (Allow Tx Reverse Flow)

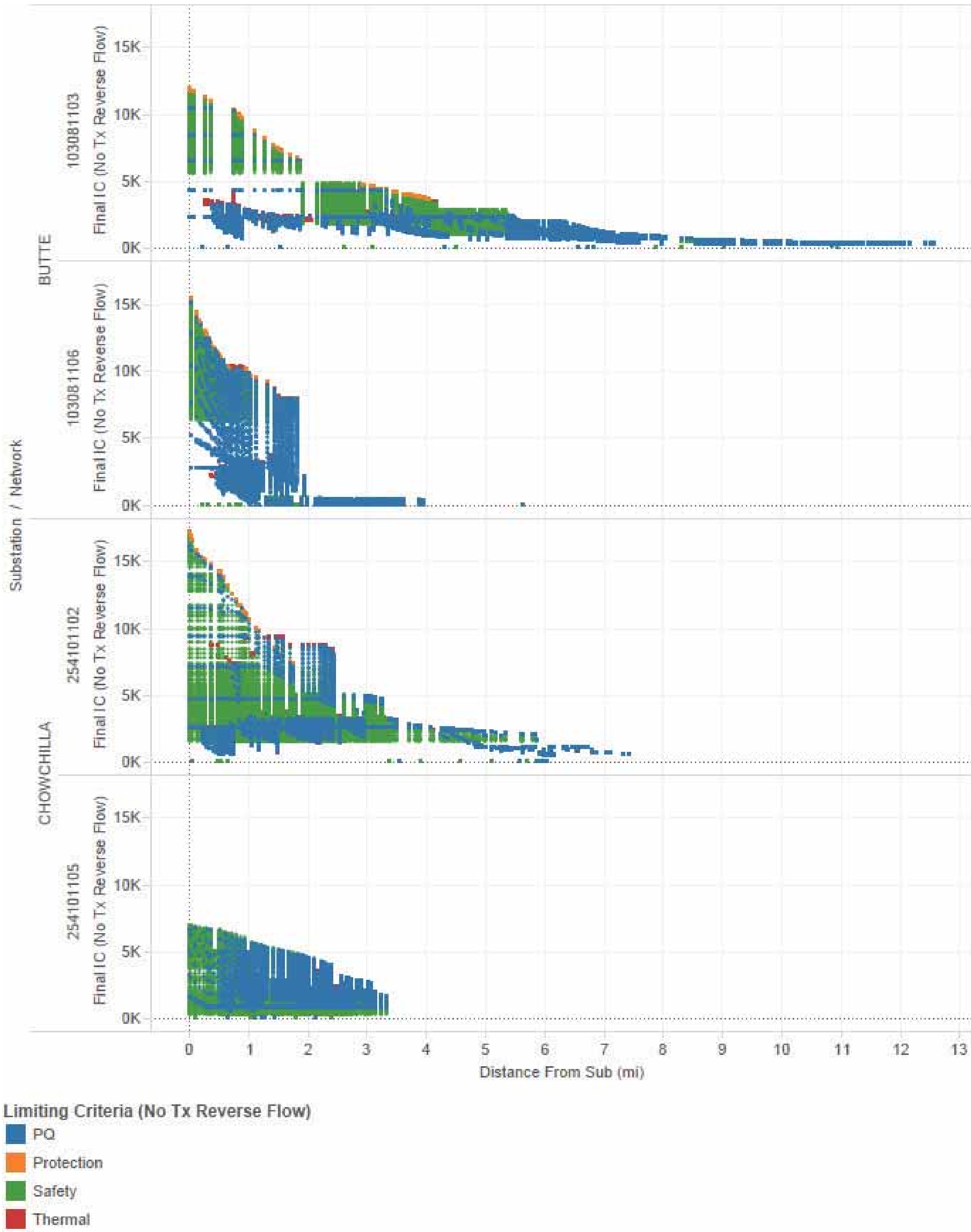

Figure 55: Final IC over Distance Colored by Limiting Criteria (No Tx Reverse Flow)

5.d Findings

This section provides some of the learnings from the results from Demo A and ongoing ICA development.

1) Streamlined would be better applied in planning analysis where iterative would be better applied in interconnection analysis

Streamlined techniques showed capabilities to provide actionable results and in some cases similar to what iterative methods determined, albeit with some deviations explained in section 6.b. One big distinction of most significance between the two methods is the processing capabilities. The iterative processing could be up to 100 times longer. The iterative approach has its place in interconnection, but the application should be more limited to specific interconnection applications and not a full system wide analyses performed on a regular basis.

2) Non related existing conditions can be hindrance on IC values

While this may be present in some cases for streamlined, it is perceived to be more of an issue within the iterative techniques. The current form of the iterative evaluates all nodes for each iteration to determine if any conditions are outside of prescribed limits. If there are any conditions outside of ranges not directly due to the DER then the ICA is limited at that location. For example, there may be a forecasted load at the end of the line that is creating a voltage below 95%. A generating DER could be placed anywhere on the circuit and this would create an ICA of 0. When placed near the low voltage issue, it may help the voltage issue but it is unclear as to what how exactly the specific coding will react to this situation. More research is needed to determine how this specific situation is to be handled.

These conditions could be more appropriately considered and handled in an interconnection study in which engineers could use human judgment to decipher these complexities. This also plays to the point in learning number 1.

3) Reverse Power Flow Limitation

Reverse flow limitations can be useful to help limit specific issues that may arise because of legacy equipment or system design. The criteria can be a very limiting factor and should be used appropriately and not loosely. The figure below shows that 32% of the nodes are limited by the reverse flow criteria. The right hand side of the chart in the safety row is showing the breakout of limiting criteria for those nodes if reverse flow limitation was not applied. It can be seen that a majority of the makeup is protection and voltage that is being limited by the safety criteria. Given the necessary development of protection criteria and known issues with voltage regulator reverse flow, this shows that the safety category would still be good to apply to ensure safe integration.

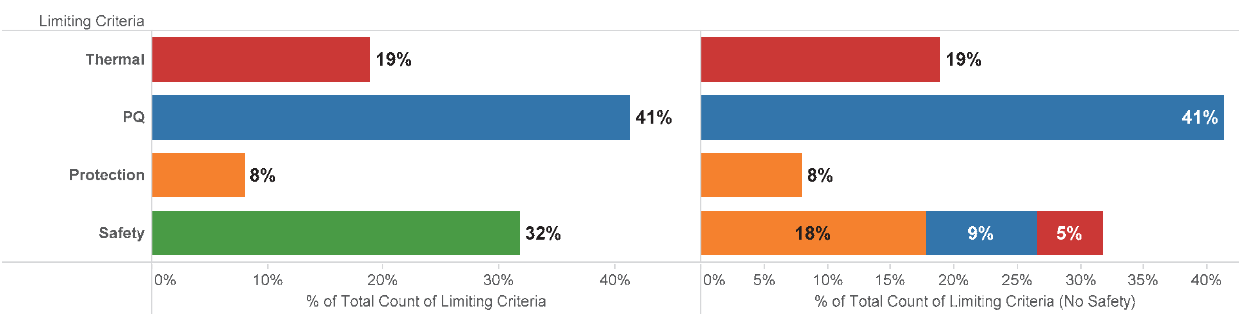

Figure 56: Limiting Criteria Comparison across No Reverse Limitation

7) In general circuit electrical characteristics provide more variation in IC than time varying loading conditions

From the summary charts in section 5.b, it can be seen that there is a lot more variation in Substation (Figure 22) and distance from sub (Figure 28) than there is by month (Figure 24) or hour (Figure 26). While these time varying conditions can be very important to specific locations, it shows that in general location is more dependent then profile. Hourly analysis should still be considered, but it may be good to ensure that locational granularity has more of a focus then timing granularity.

8) There is still much to learn and analyze

Integration capacity is a very complex topic covering many various components of power system operation and design. Because of this there is many ways to evaluate and assess the data with endless questions to try to answer. Industry and working group

Collaboration will help move ICA in a direction that ensure a robust and efficient methodology going forward.

5.d.i Processing and Size of Data

The initial analysis for the 2015 DRP analyzed approximately 500,000 three phase primary distribution nodes across about 100,000 established zones within the 3,000 radial distribution feeders. That analysis utilized streamlined only and simulated one power flow and one short circuit analysis per feeder within CYMDIST. Utilizing the load profiles from LoadSEER the peak hour results were then scaled to perform the hourly analysis for each DER which then produced the minimum ICA throughout the year. That analysis processing time was as follows:

- **CYMDIST:** 15-20 hours of simulation (1 power flow and 1 short circuit per feeder)
  - 18-24 seconds on average per circuit
- **SQL:** 1 hour * X number of DER types
- **Total:** 25-30 hours for 10 DER types

A key component to Demo A is to increase the confidence of accuracy for the hourly results. This is being handled two fold. The first is to rely on a power flow simulation for each hour versus scaled results based on a peak power flow within the streamlined method. The second is to explore iterative power flow methods which significantly increase the amount of power flow simulations. The new analysis general processing times are as follows:

- **Streamlined:** 400 hours of simulation for 60 circuits
  - 1-3 seconds per power flow (single hour)
  - 400 seconds on average per circuit

- **Iterative:** 6,000 hours of simulation for 60 circuits
  - 30-60 seconds per simulation set (single hour)
  - 5000 seconds on average per circuit

The final results with all scenarios created a massive dataset across the limited feeder set that only represents 2% of the PG&E territory:

- **Total Rows:** ~350 million
- **Average Rows per Feeder:** ~6 million
- **Total Report Table Size:** ~100 GB (varies based on database optimization)

This doesn't include all the prep tables created with all the intermediate data to do all the expanded analysis and post processing. It only represents the dataset of ICA results that is desired to be shared. It is acknowledged that there are avenues of data optimization and database management to be explore to better optimize databases. More about computation and data management can be found in Section 9.a.

6 COMPARATIVE ASSESSMENT

6.a General Description

There are two main components of comparative assessment that are desired within Demo A. The first is an assessment of how aligned the IOUs can be despite different tools and slight differences in approach. The second is to determine difference between methods of more streamlined techniques versus iterative techniques. Section 6.b describes the comparison between methods while section 6.c describes the comparison between IOUs.

6.b Comparison between two methods

The purpose of this assessment is to determine how different these approaches are and what that would mean for ICA. In general the streamlined approach is focused on speed and abstraction of analysis across components while the iterative is focused on detail and precision of power flow results closer to what may be seen in an interconnection study.

It was the original intent to use iterative as a baseline to compare streamlined against. However, after exploration of this technique it was noticed that it is not that straight forward. There are some limitations to the iterative technique that provide accurate power flow results, but limit the ability to understand and create concise hosting capacity results. For instance, the iterative approach is very restrictive on limitations based on its interaction on the whole circuit. Iterative IC can be declared 0 for issues not relating to the new DER. In some cases this is preferred in order to understand the broader effect of the DER. In other cases existing conditions could create a limitation on ICA that shouldn't apply to that DER at that location.

Other nuances in the structure of the calculations limited ability to separate out as necessary. For instance the voltage regulator impact in streamlined was not analyzed separately from reverse flow in general. This was a feature of the iterative module within CYMDIST. Another component is that the iterative module locked all voltage regulating devices for all iterations of power flow. This reduces the ability to understand the true impact of the voltage regulating devices on the circuit. Future work can explore this further, but in general it provides a caution to blindly trusting iterative results as the baseline.

6.b.i Approach

The general approach taken was to focus on the reference circuit and compare graphically to ensure general trending and tracking. Due to the discussed revelations above, this approach was taken rather than a quantitative approach given the still developmental components of the analysis.

6.b.ii Findings/Conclusions

The following section describes some of the results from the comparative assessment as well as some conclusions and learnings. The first section talks about comparison on the IEEE reference circuit. The second section discusses the conclusions and learnings.

Comparison using IEEE 123

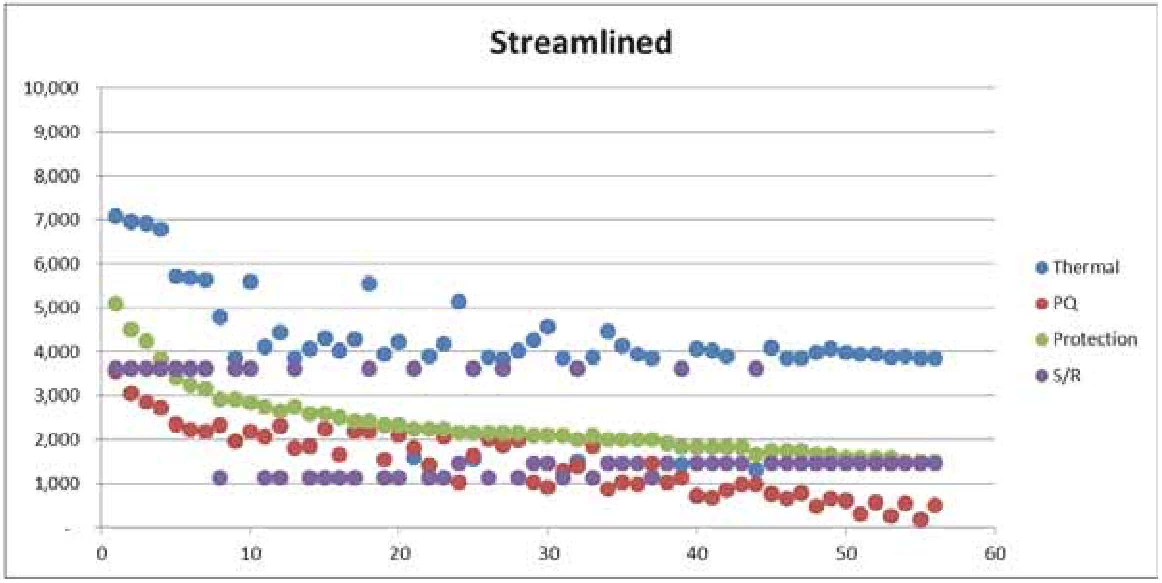

Figure 57: IEEE 123 Streamlined Criteria IC Results over Distance

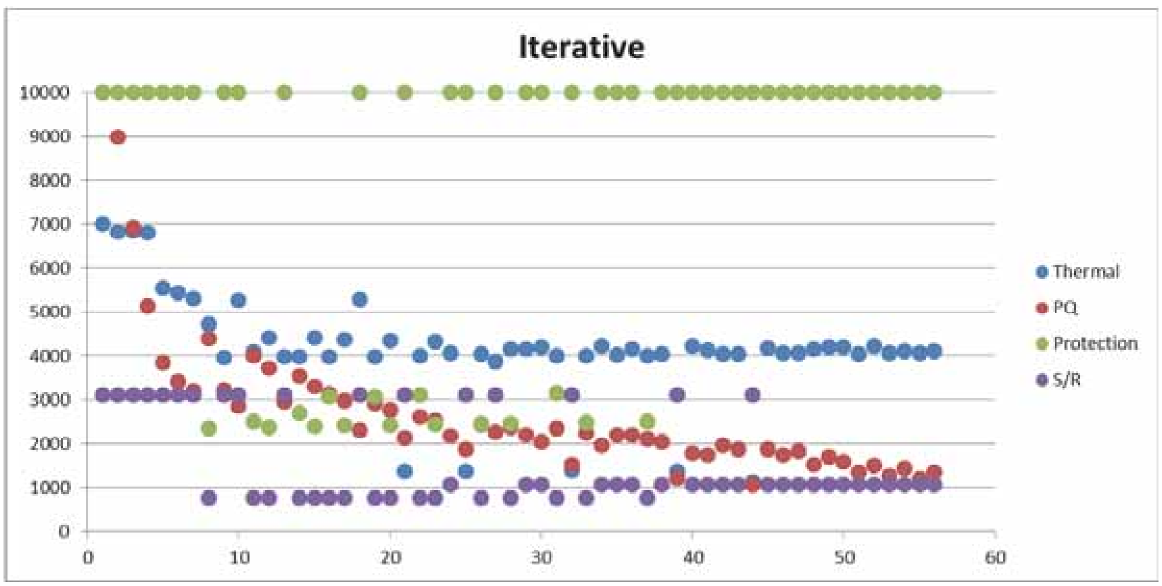

Figure 58: IEEE 123 Iterative Criteria IC Results over Distance

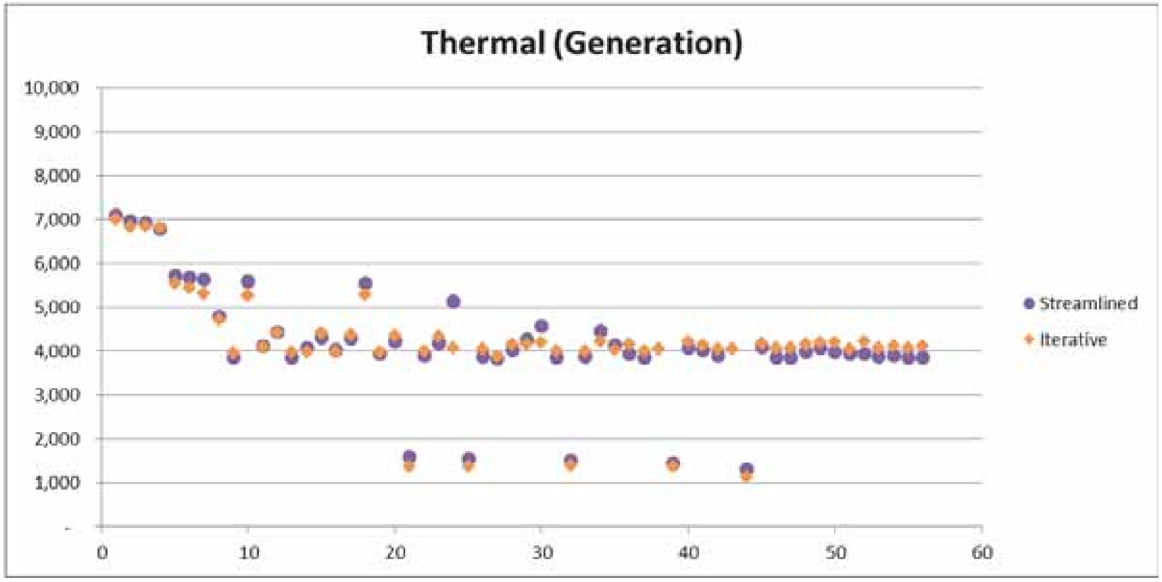

Figure 59: IEEE 123 Thermal IC Results over Distance

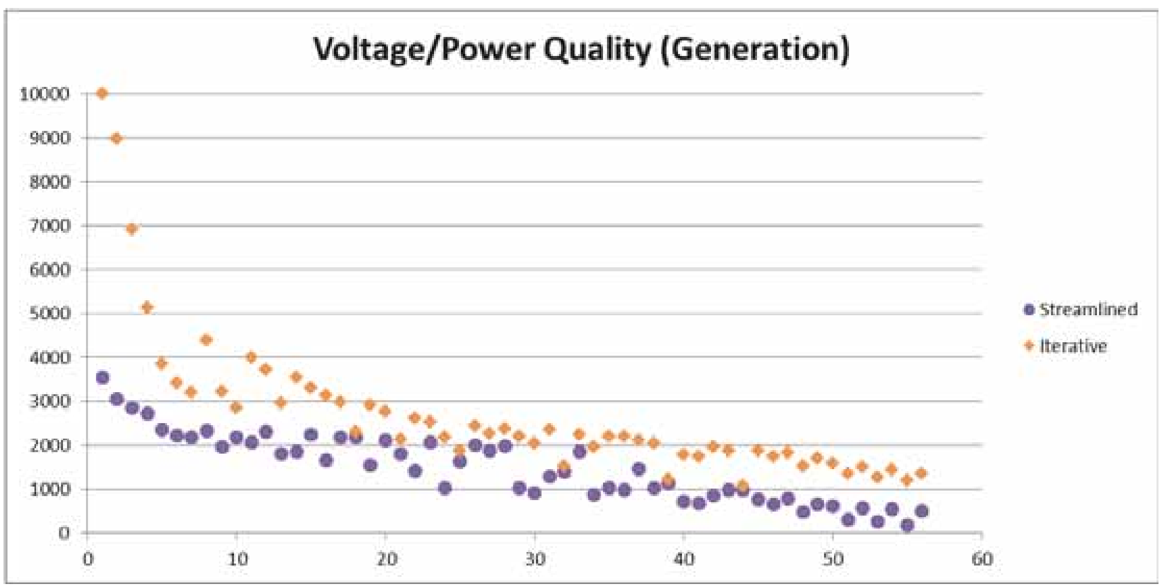

Figure 60: IEEE 123 Voltage/PQ IC Results over Distance

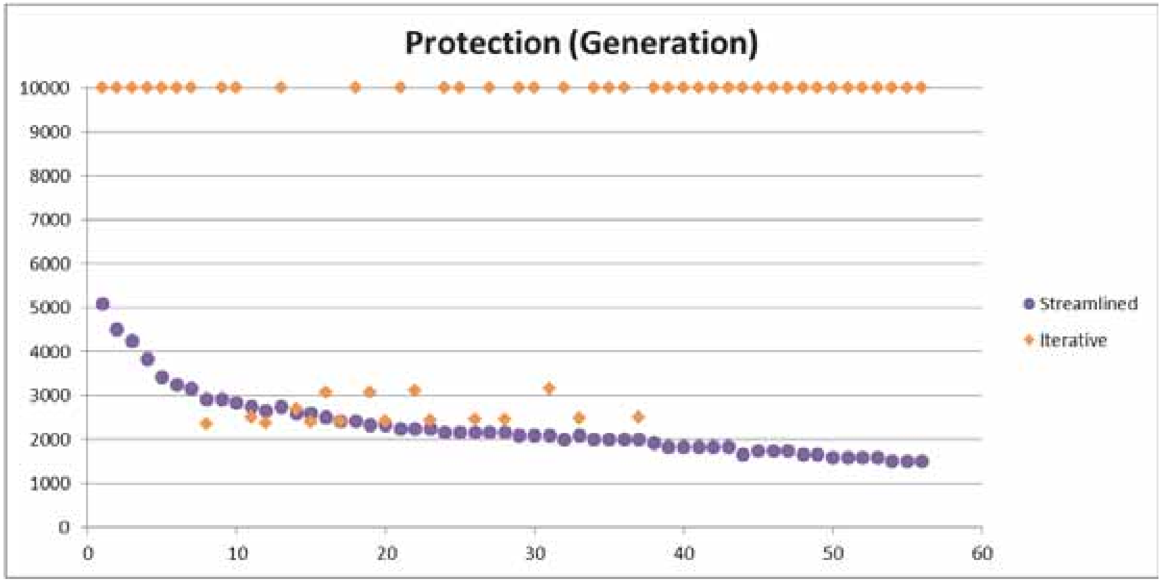

Figure 61: IEEE 123 Protection IC Results over Distance

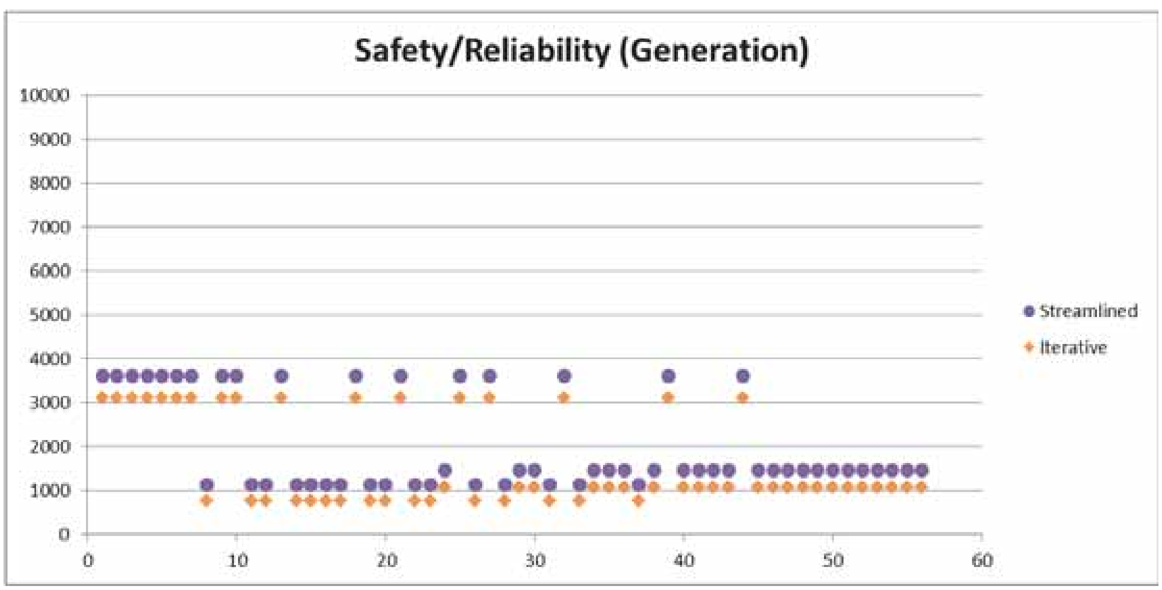

Figure 62: IEEE 123 Safety/Reliability IC Results over Distance

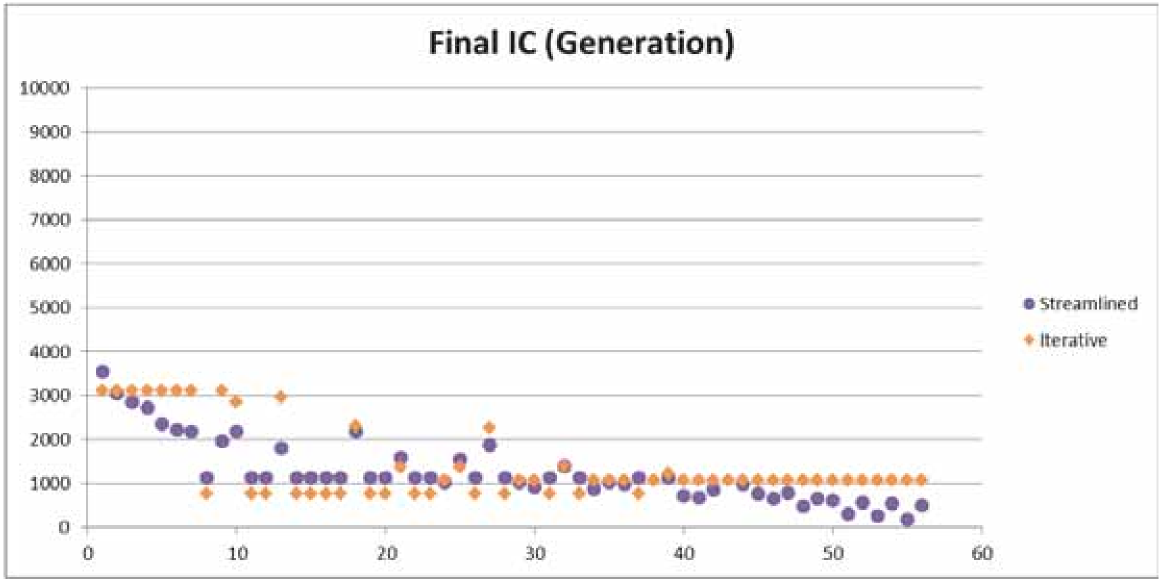

Figure 63: IEEE 123 Final IC Results over Distance

The two biggest variations across the major criteria were in voltage and protection. Within protection, the difference was intuitive and discussed below. For the voltage criteria, the figures below deep dive into the sub criteria to gain an understanding of the discrepancy.

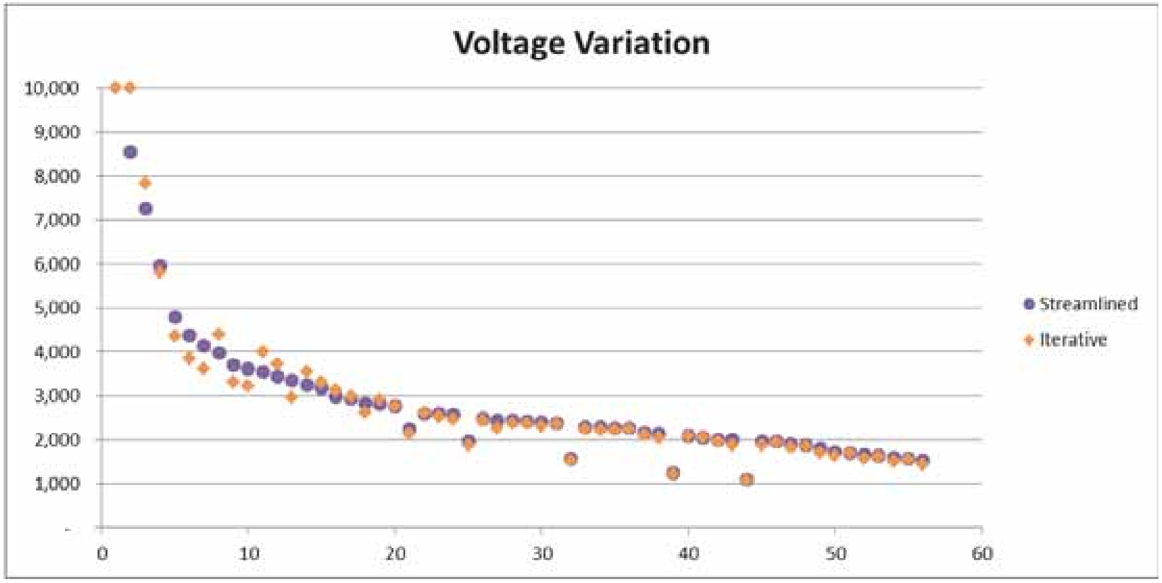

Figure 64: IEEE 123 Voltage Variation IC Results over Distance

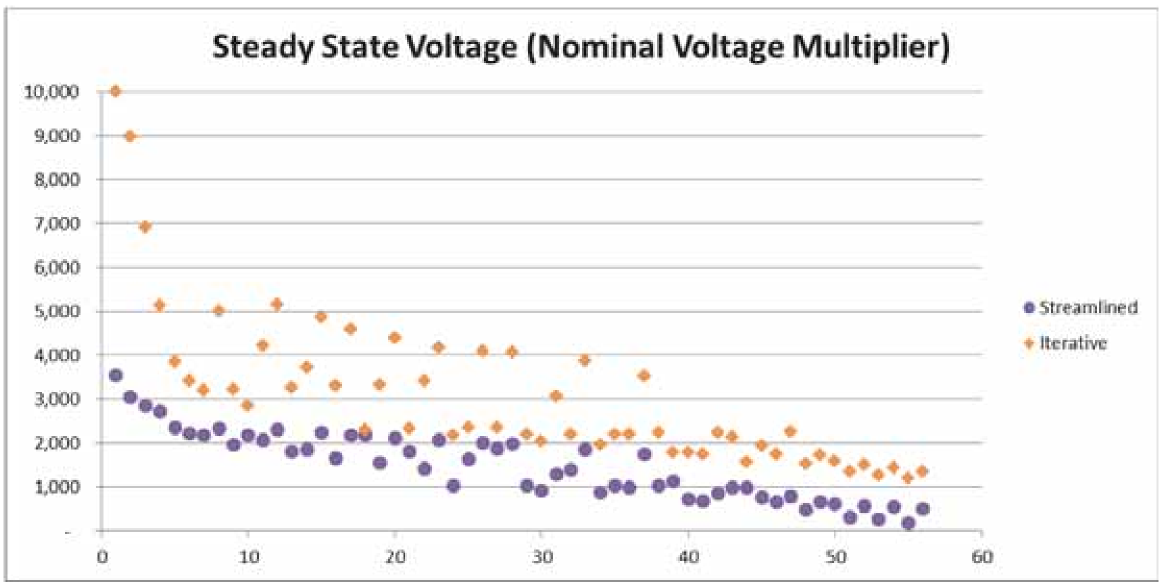

Figure 65: IEEE 123 Steady State Voltage IC Results over Distance (Nominal Voltage Multiplier)

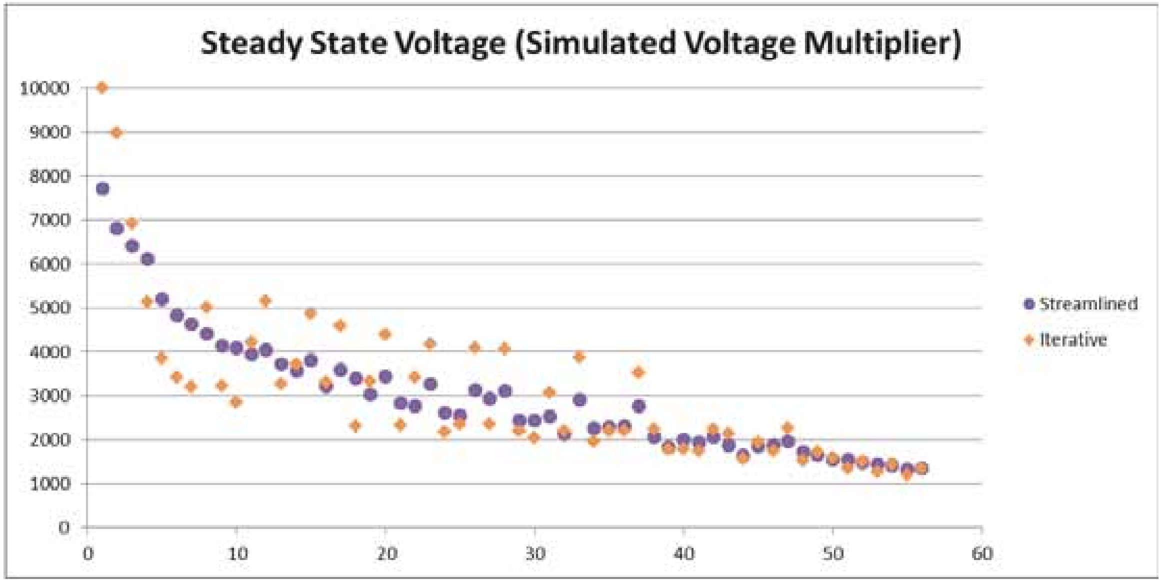

Figure 66: IEEE 123 Steady State Voltage IC Results over Distance (Simulated Voltage Multiplier)

It can be seen in these additional figures that voltage variation tracks really well between the two techniques. The main discrepancy was discovered in the steady state criteria. After some discussion and research, it was discovered that the voltage multiplier for the per unit voltage headroom was using nominal voltage (a.k.a. base voltage). The results were re-calculated using the simulated voltage at each node as the multiplier to per unit headroom. The voltage criteria tracked much better with this adjustment. That said there are some specific deviations that still occur and could be researched as to what causes them.

Learnings and Conclusions

1) Protection Criteria needs more research

The protection criteria at this stage focused on reduction of reach and utilized the short circuit contribution ratio method within streamlined. The main difference seen in Figure 61 is that the iterative more directly tied calculations to the protective zones and device settings. The general SCCR approach in streamlined was not too far off for the nodes downstream of the recloser given the settings and thresholds used for each. That being said there could be some logic for the streamlined threshold to dynamically adjust based on upstream protective device settings. PG&E would like to explore this further.

Through EPRI's research[9] there have been other identified methods within streamlined to better calculate the specific protection criteria outlined to be potential issues. It is PG&E's desire to explore these additional protection criteria before any major conclusions can be made for protection.

2) Voltage Variation is similar between both methods

Voltage variation is one of the simpler algorithms and was not expected to be dependent that much on load conditions and more so the configuration of the feeder. This calculation utilized nominal voltage and did not require load calculations for each hour. The comparison between the two tracked rather well and not much tweaking is expected for this criterion.

3) Steady State Voltage may require adjustments in parameters

The streamlined steady state voltage IC resulted a little lower in comparison to the iterative IC. The trend is similar with some variation. Figure 65 shows this when using nominal voltage as the multiplier to headroom in the equation. Figure 66 shows the comparison when using the simulated voltage as the multiplier to the headroom value. While the values are much closer, there still are some differences. Specific evaluation of these deviations may be able to decipher if extra variables/logic could be inserted to better match these values.

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[9] *A New Method for Characterizing Distribution System Hosting Capacity for Distributed Energy Resources: A Streamlined Approach for Solar Photovoltaics*. EPRI, Palo Alto, CA: 2014. 3002003278

4) In general the ICA can track similar, but direct comparison may not feasible

It was determined that iterative is not as straight forward, especially when applying towards more complex circuits. Initial evaluation of the demo circuit results for iterative (1) do not always provide an answer due to non-convergence in the power flow simulations and (2) had a huge sensitivity to other indirect conditions within the circuit. These also add to PG&E' perspective that iterative should be more focused to specific situations in which more control and awareness of application can be applied.

6.c Comparison among IOUs

Assessment began with the IEEE 123-node feeder in order to ensure general alignment with an easy to review small data set. Utilizing this smaller dataset was important provided the complexity of the methodologies being evaluated. Starting with a complex dataset for comparison would have been too much of a time burden and obstacle. Two main topics of challenges were found in the process. The first was making sure the models were identical. The second was ensuring all the starting points and power flow settings were the same.

The power flow tools allow for the vast amounts of settings and parameters in order for models to simulate the specific conditions necessary for evaluation. The IOUs have learned many aspects in the parameters of the tools which allowed the IOUs to drive to better alignment in the technical assumptions that go into the power flow.

6.c.i Approach

During this comparison assessment, the streamlined and iterative ICA results are compared among the IOUs as to insure the most alignment on the methodologies, assumptions and simulation parameters. Utilities adopted the IEEE 123 node test feeder as reference feeder for this comparison. The IEEE 123 node test feeder has established data set of power flow results and is publicly available for stakeholders to also test and verify results. This test feeder is characterized by both overhead and underground lines, unbalanced loading with constant current, impedance and power. It operates at a nominal voltage of 4.16 kV which is not the most commonly used voltage level but it does provide voltage drop issues that must be solved with voltage regulation applications such as voltage regulators and shunt capacitors.

SCE and PG&E use CYMDIST as their power system analysis tool while SDG&E uses Synergi as its power system analysis tool. For this reason, the power flow results between these two tools are compared first to ensure simulation environment consistency. The ICA results are then analyzed with the understanding of any error margins existing in the power flow models.

6.c.ii Findings/Conclusions

Challenges in model alignment were first resolved by ensuring the base dataset was properly coded in the dataset required by the specific tools. PG&E and SCE were able to align on an already established circuit model from CYME, however, Synergi had not previously established such model which had to be created prior to commencing the comparison process. Once created some differences in how the tools handle some components provided some variation. For power flows the main component of this was the regulator. While variation has been reduced to a minimal amount, it is still being evaluated why CYME and Synergi assume different impedances for the regulator.

The other side to the differences was around the starting assumption and parameters that can be used for the power flow tools. The utilities collaborated to align on many of these values which are:

- Power Flow Calculation Method
- Convergence Parameters
- Line Transposition and Charging
- Voltage Sensitivity Load Models
- Regulator Tap Operation Models
- Starting Voltages
- Pre-Fault Voltages

Another component of this is the various amounts of electrical values that can be retrieved from the tool to analyze such as:

- A/B/C Phase Voltages
- Min/Max/Avg Voltages Real and Apparent Power

Model Comparison

For the power flow, it has been observed that there is a slight deviation across a few characteristic within the model. The IOUs were confident that the magnitude of these differences was not significant enough to warrant issues. That being said, there is an expectation that the differences will likely show up in IC values to create similar offsets. Below are a few graphs showing the comparison between the Synergi and CYME model simulations.

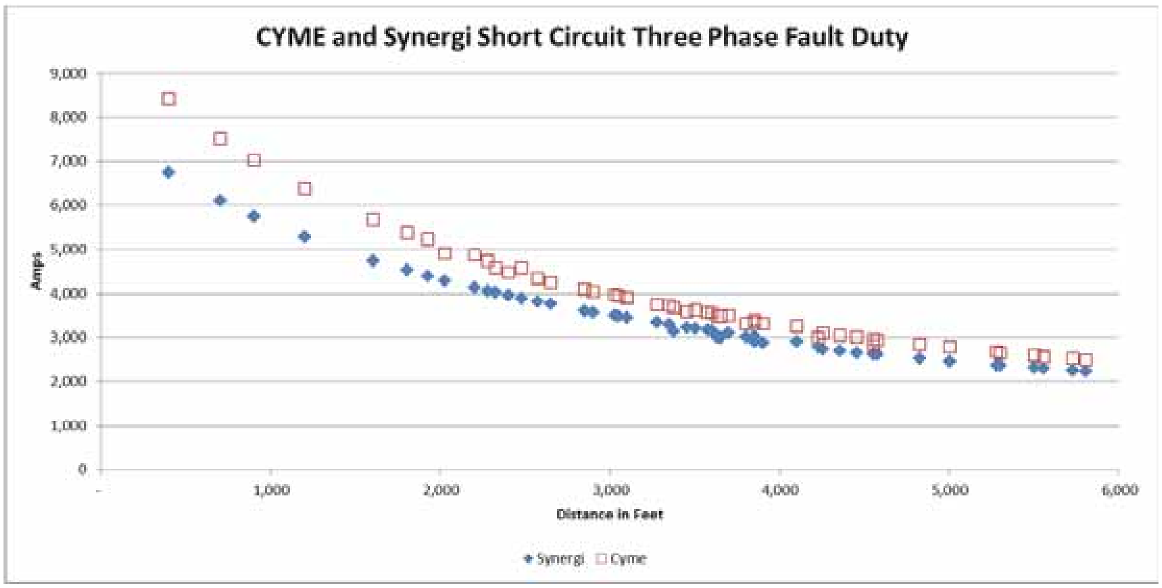


Figure 67: Short Circuit Fault Duty Comparison with Average Difference of 13%

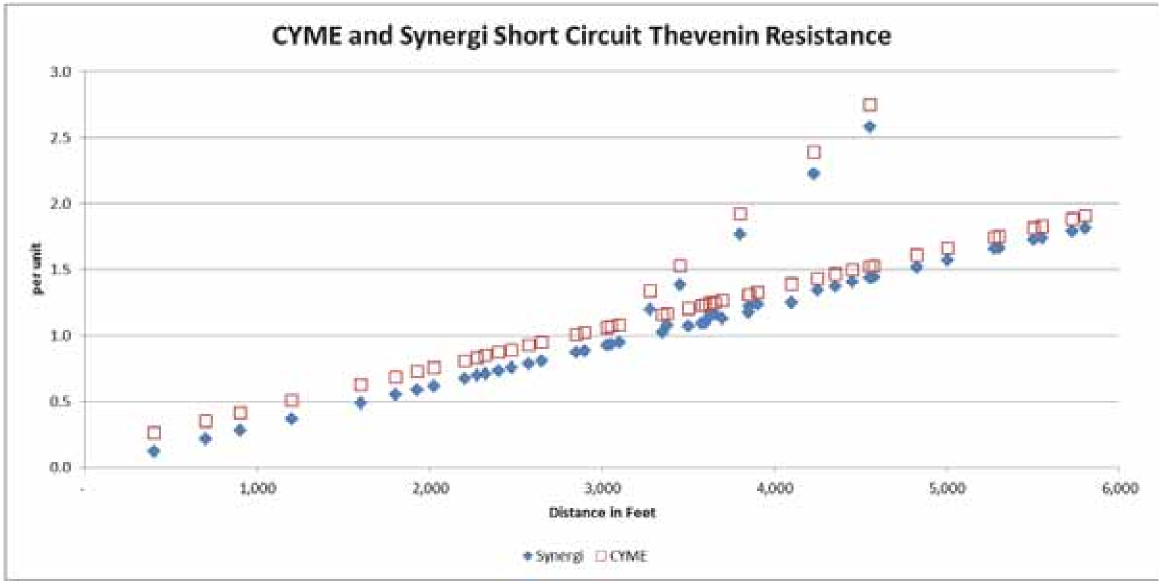


Figure 68: Short Circuit Resistance Comparison with Median Difference of 14%

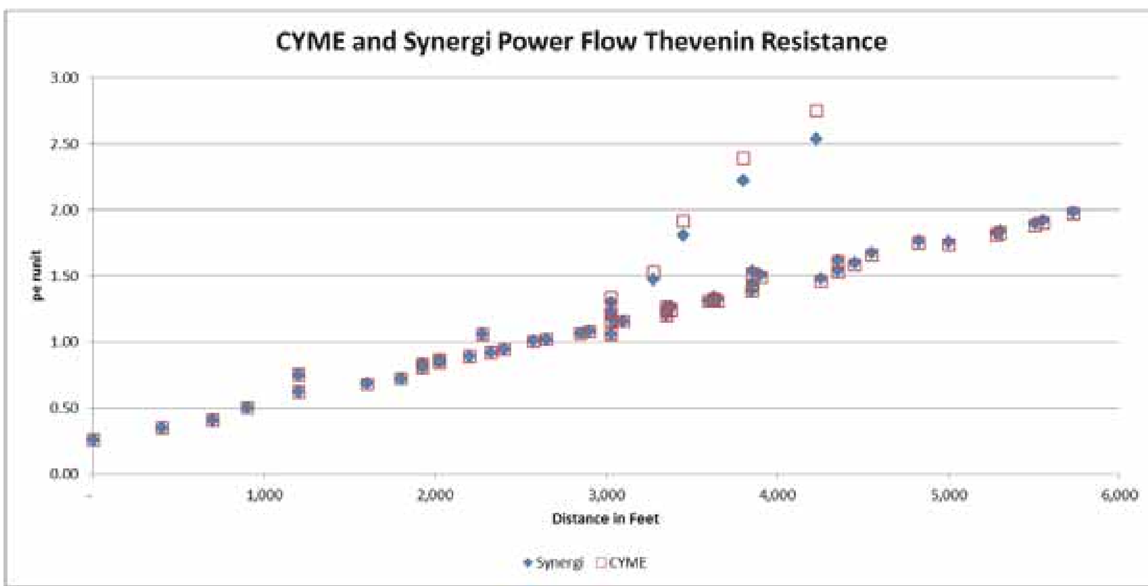


Figure 69: Power Flow Resistance Comparison with Average Difference of 1.0%

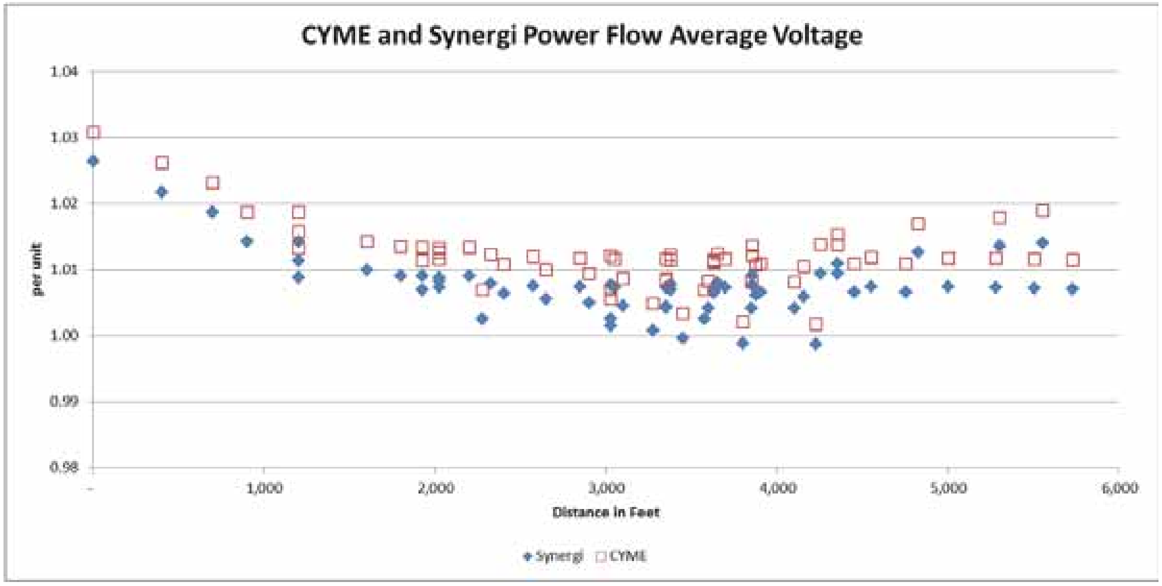


Figure 70: Average Voltage Comparison with Average Difference of 0.43%

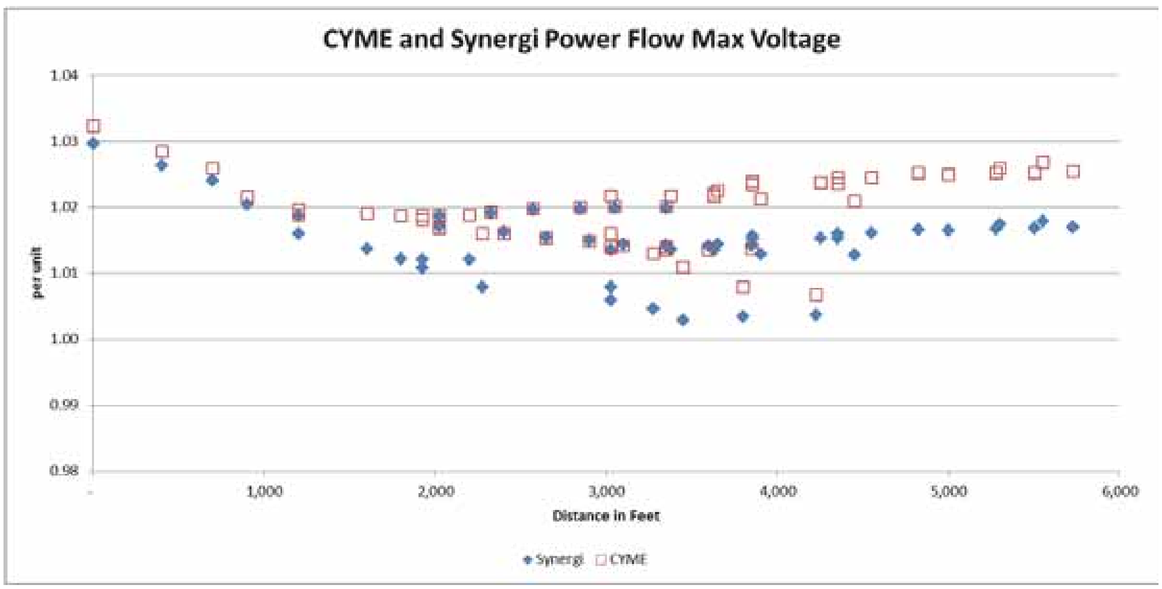


Figure 71: Maximum Voltage Comparison with Average Difference of 0.5%

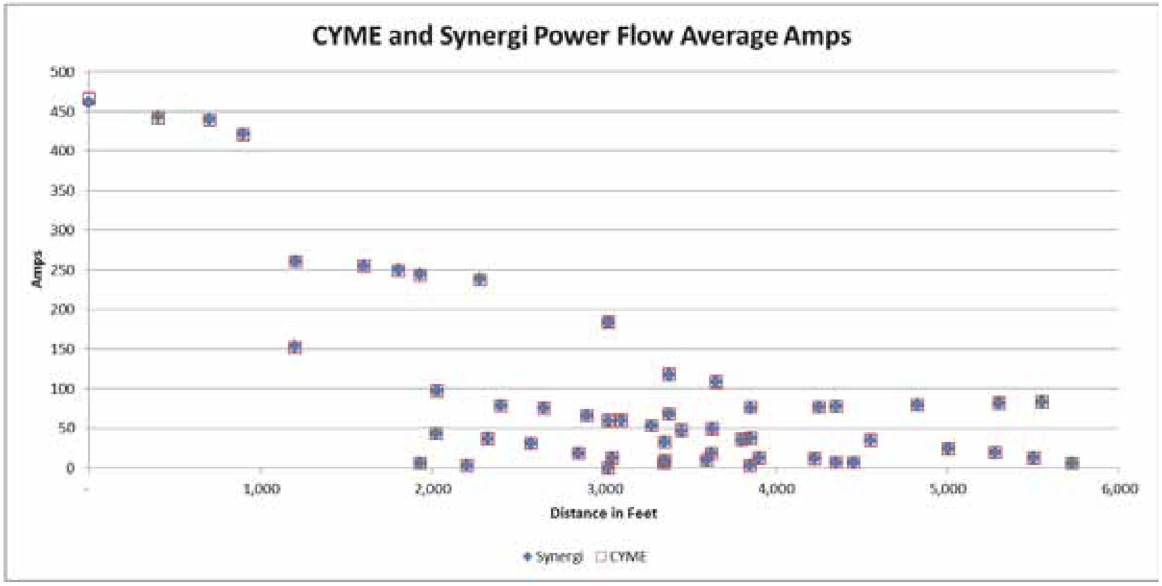


Figure 72: Average Amps Comparison with Average Difference of 0.3%

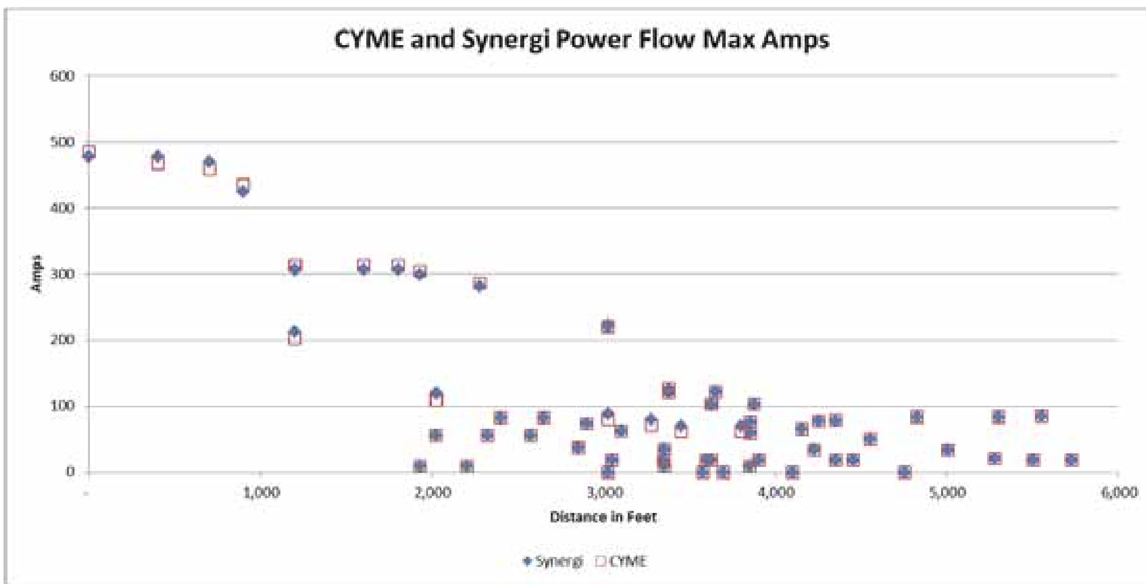


Figure 73: Max Amps Comparison with Average Difference of 2%

Streamlined Comparison

The following figures depict the comparison across specific criteria across the three IOUs. Overall the IC values track each other similarly and don’t have significant variation. The little variation seen is mainly believed to be due to the variation in power flow models. Slightly higher voltages will provide slightly lower IC and is observed for Figure 75 in comparison to Figure 70 and Figure 71.

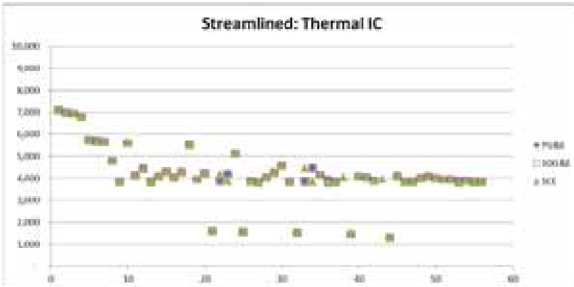


Figure 74: Streamlined Thermal IC Comparison

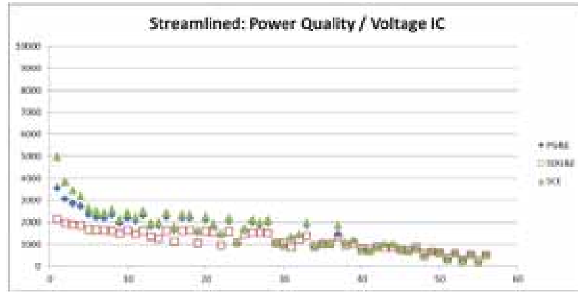


Figure 75: Streamlined PQ IC Comparison

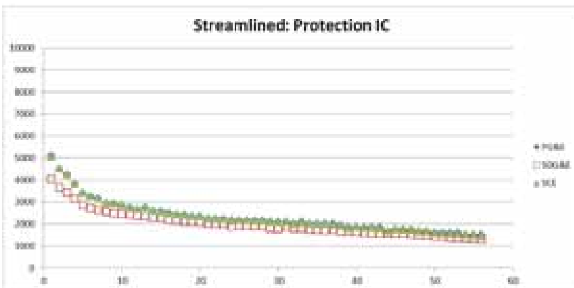


Figure 76: Streamlined Protection IC Comparison

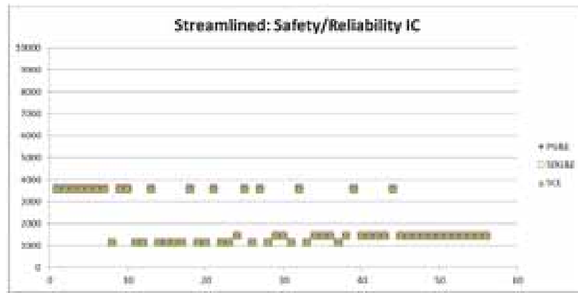


Figure 77: Streamlined S/R IC Comparison

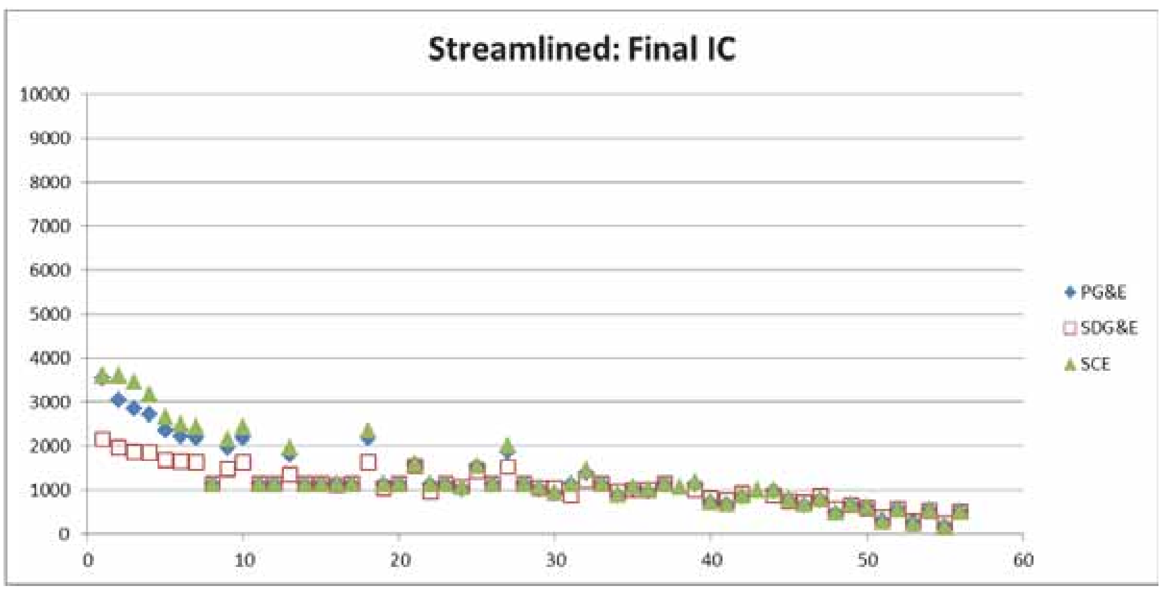


Figure 78: Streamlined Final IC Comparison

Iterative Comparison

The following figures depict the comparison across specific criteria across the three IOUs. Overall the IC values track each other similarly, but have a little more variation than the streamlined. The deviations are a little more pronounced in iterative. While it is believed that the methodologies are generally aligned there are still development and implementation bugs to be worked out with the software developers.

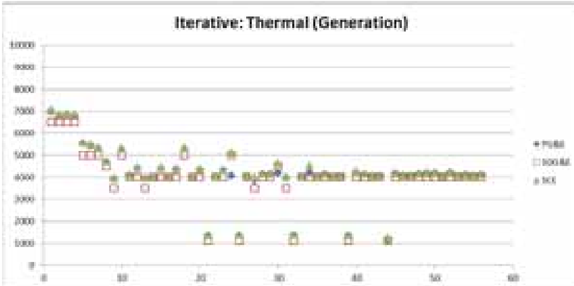


Figure 79: Iterative Thermal IC Comparison

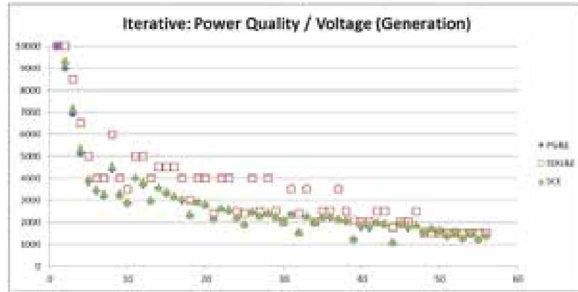


Figure 80: Iterative PQ IC Comparison

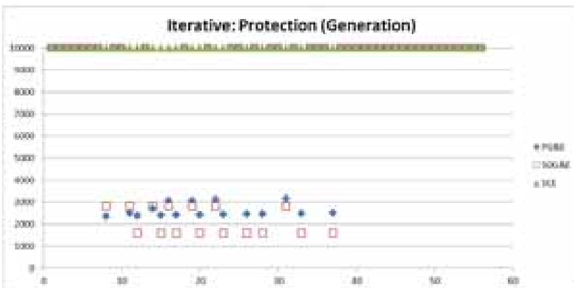


Figure 81: Iterative Protection IC Comparison

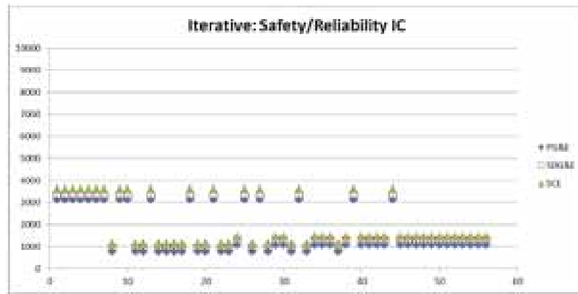


Figure 82: Iterative S/R IC Comparison

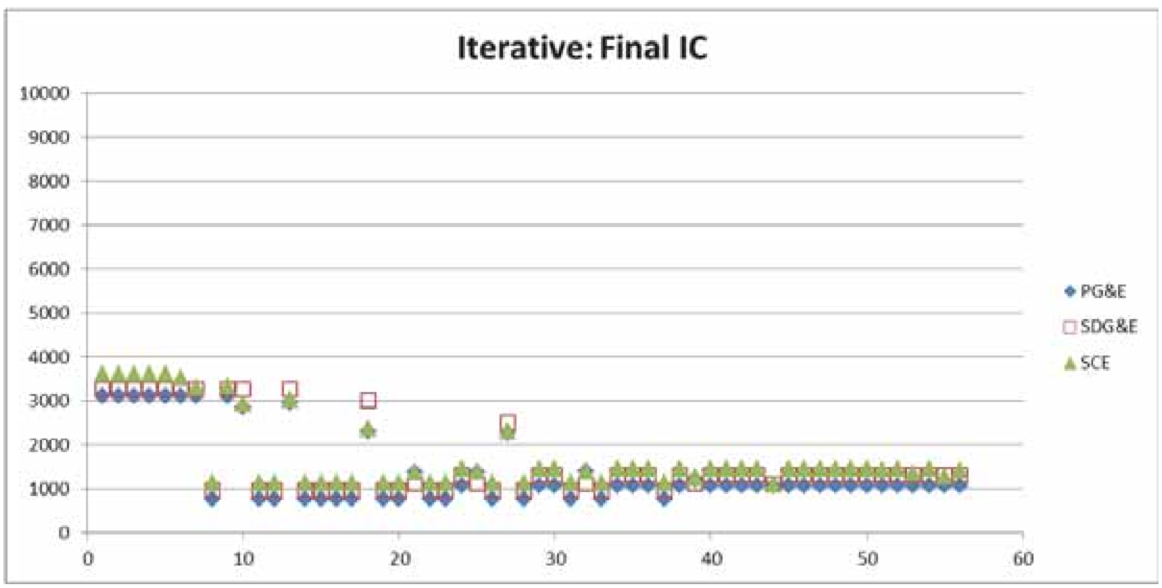


Figure 83: Iterative Final IC Comparison

7 MAP DISPLAY

7.a General Description

The PV RAM map was originally created to help customers and developers identify potential project sites by providing information on locations of distribution and transmission lines, distribution load and interconnection queue. PG&E’s initial Integration Capacity Analysis results can be found in the Renewable Auction Mechanism (RAM) Map on PG&E’s website as of July 1, 2015. The RAM map currently has a coloring scheme that depicts the capacity level of a line section by a color gradient to better display the varying levels of capacity by location on each feeder. This coloring scheme is intended to help DER developers and customers better understand where on a circuit location of a DER is better suited.

Figure 84 and Figure 85 show how PG&E presented its Integration Capacity results on its RAM Map. PG&E provides customers with limitations of the substation feeders and transformer banks alongside line section results. The additional feeder limit and substation bank limit in the Substation DER Capacities column were intended to better assist wholesale customers that may want to connect using dedicated feeders or developers targeting multiple line sections.

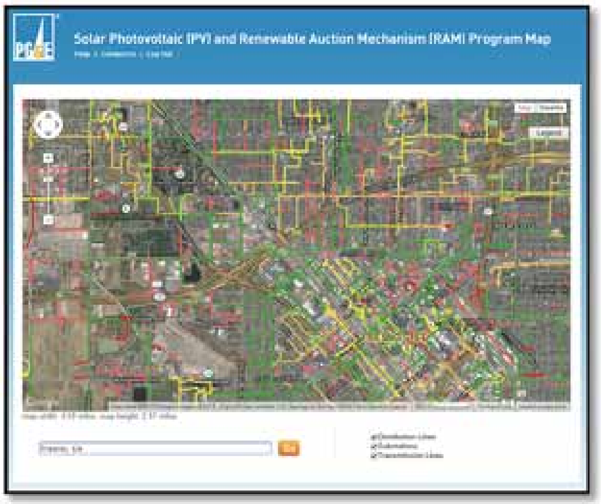


Figure 84: Screenshot of RAM Map with Integration Capacity Coloring

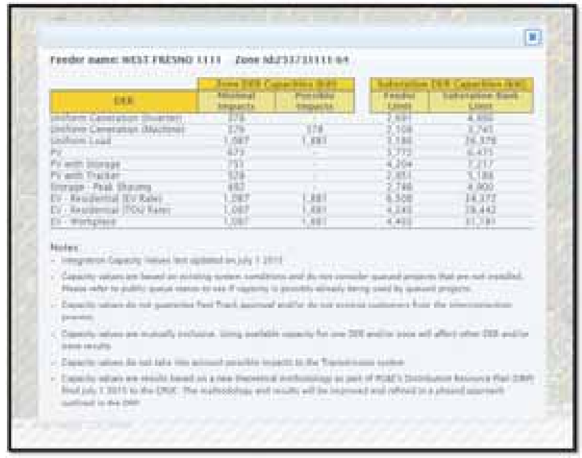


Figure 85: Screenshot of RAM Map with Integration Capacity Results

PG&E is still in the process of consolidating and finalizing the result set for publication and visualization on the maps. PG&E will notify the ICAWG and CPUC when final datasets are ready to be shared. It is expected that they will be ready in January.

7.b Proposed Updates to Map

With the various scenarios the ICA calculation needs to examine, there will be a large amount of data generated during Demo A. Publishing all these data on the map will require significant computation resources which not only affect the user experience due to longer time required to load information but also impose challenges to the map development. In addition, publishing all the ICA results on the map requires longer learning curves and more efforts for users to correctly retrieve the desired information while navigating through various scenarios. All the information published and made available will be subject to Personal

Identifiable Information (PII) or Critical Energy Infrastructure Information (CEII) compliance requirements.

The scenario to be presented in the online map is the IC value which is the "final" ICA results based on the most limiting power system criteria and the most limiting hour.. The symbology, also known as the heat map visualization, of the maps will be based on this value as well. Red colors will be areas of low IC, while green areas will be areas of high IC.

7.b.i Map Format

Distribution Planning Area (DPA) Layer

When users click the DPA area, the pop-up window will show the DPA type, load profile, and the link for downloading the complete Demo A dataset. The two load profiles presented are for typical high-load days and typical low-load days. The load profiles may be aggregated from the circuit load profiles and may be displayed in the DPA view.

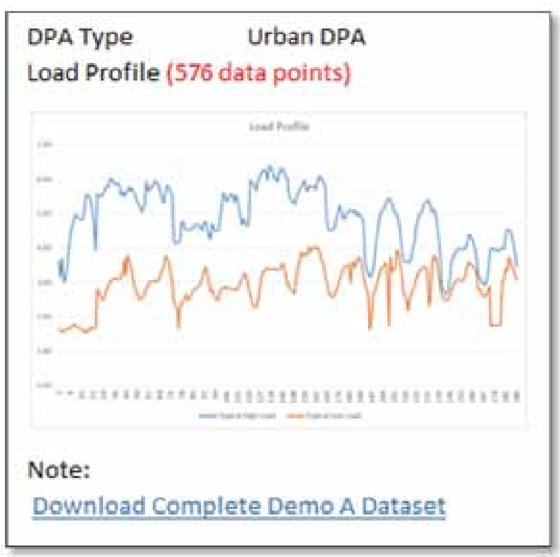


Figure 86: DPA Layer Information

Substation Bank Layer

When users click a substation, the pop-up window will show the substation name, load profile, and the link for downloading the complete Demo A dataset. The two load profiles presented are for typical high-load days and typical low-load days. The load profiles are aggregated from the circuit load profiles in the substation.

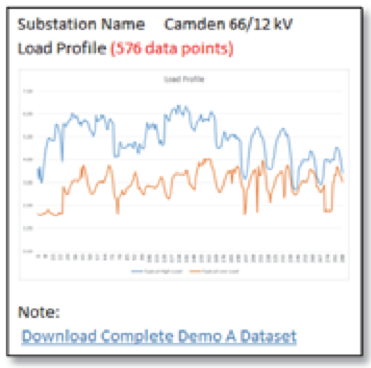
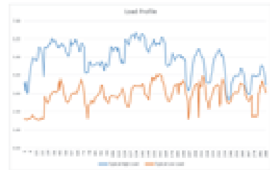


Figure 87: Substation Layer Information

Feeder Layer

When users click a circuit, the pop-up window will show the circuit name, voltage, customer type breakdown (residential, commercial, industrial, agricultural) in percentage[10], existing generation, queued generation, total generation, load profile, and the link for downloading the complete Demo A dataset. The two load profiles presented are for typical high-load days and typical low-load days.

[10] Using percentage of customer type breakdown, instead of actual customer count, may prevent violating any applicable data sharing limitations to certain extent, but data sharing limitations will still be examined to make sure there are no violations.



Circuit Name	Solitaire
Voltage (kV)	12
Residential Customer (%)	50
Commercial Customer (%)	20
Industrial Customer (%)	10
Agricultrual Customer (%)	20
Existing Generation (MW)	1.02
Queued Generation (MW)	2.00
Total Generation (MW)	3.02
Load Profile (576 data points)	
Note:	
Download Complete Demo A Dataset	

Figure 88: Circuit Layer Information

Circuit Segment Layer

When users click a line segment or node, the pop-up window will show the associated circuit name, voltage, line segment number, final integration capacity values for uniform generation and uniform load, respectively, and the link for downloading the complete Demo A dataset.

Circuit Name	Solitaire
Voltage (kV)	12
Line Segment Number	2
Integration Capacity, Uniform Generation (MW)	3.00
Integration Capacity, Uniform Load (MW)	4.00
Note:	Generation ICA assumes short circuit duty characteristics of inverter-based technology. Values presented reflect the 2-year growth scenario (utility planning), with no reverse power flow.
Download Complete Demo A Dataset	

Figure 89: Circuit Segment Layer Information

As the note shown in Figure 5 indicates, the generation ICA assumes short circuit duty characteristics of inverter-based technology.

7.b.ii Downloadable Data Format

The ICA results under various scenarios will be available in a download format. Users can download the complete Demo A data set through the links at any layer as shown in Figures 2-5.

ICA Results

Figure 6 shows a sample ICA data table. The sample table is created using MS Excel; however, as the complete dataset will contain millions of records, the actual data file will be in a file format that accommodate the amount of data, such as a *.csv.

Users can query the dataset to obtain the desired information. For example, the ICA values for a given circuit segment with DER growth scenario III and allowing reverse power flow at the substation busbar can be filtered.

DPA	Substation	Circuit Name	Line Segment	DER Technology	DER Forecast	Scenario	Month	Load Day	Hour	ICA_Thermal	ICA_Voltage/PQ	ICA_Protection	ICA_Safety	Final ICA
Urban DPA	Camden 66/12 kV	Solitaire	1	Uniform Generation	Base	No-Reverse	January	High_Load	1	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	1	Uniform Generation	Base	No-Reverse	February	High_Load	2	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	1	Uniform Generation	Base	No-Reverse	March	High_Load	3	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	1	Uniform Generation	Base	No-Reverse	April	High_Load	4	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	1	Uniform Generation	Base	No-Reverse	May	High_Load	5	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	1	Uniform Generation	Base	No-Reverse	June	High_Load	6	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	1	Uniform Generation	Base	No-Reverse	July	High_Load	7	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	1	Uniform Generation	Base	No-Reverse	August	High_Load	8	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	1	Uniform Generation	Base	No-Reverse	September	High_Load	9	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	1	Uniform Generation	Base	No-Reverse	October	High_Load	10	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	1	Uniform Generation	Base	No-Reverse	November	High_Load	11	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	1	Uniform Generation	Base	No-Reverse	December	High_Load	12	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	1	Uniform Generation	Base	No-Reverse	January	High_Load	13	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	1	Uniform Generation	Base	No-Reverse	January	High_Load	14	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	1	Uniform Generation	Base	No-Reverse	January	High_Load	15	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	1	Uniform Generation	Base	No-Reverse	January	High_Load	16	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	1	Uniform Generation	Base	No-Reverse	January	High_Load	17	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	1	Uniform Generation	Base	No-Reverse	January	High_Load	18	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	1	Uniform Generation	Base	No-Reverse	January	High_Load	19	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	1	Uniform Generation	Base	No-Reverse	January	High_Load	20	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	1	Uniform Generation	Base	No-Reverse	January	High_Load	21	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	1	Uniform Generation	Base	No-Reverse	January	High_Load	22	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	1	Uniform Generation	Base	No-Reverse	January	High_Load	23	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	1	Uniform Generation	Base	No-Reverse	January	High_Load	24	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	2	Uniform Generation	Base	No-Reverse	January	High_Load	1	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	2	Uniform Generation	Base	No-Reverse	January	High_Load	2	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	2	Uniform Generation	Base	No-Reverse	January	High_Load	3	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	2	Uniform Generation	Base	No-Reverse	January	High_Load	4	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	4	Uniform Generation	Base	No-Reverse	December	High_Load	23	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	4	Uniform Generation	Base	No-Reverse	December	High_Load	24	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	1	PV System	DER1	Reverse	February	Load_Load	1	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	2	PV System with Tracker	DER5	No-Reverse	March	High_Load	4	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	3	EV – Res (EV Rate)	Base	Reverse	April	Load_Load	5	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	4	EV – Res (TOU Rate)	DER1	No-Reverse	May	High_Load	7	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	1	EV – Workplace	DER3	Reverse	June	Load_Load	9	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	2	Uniform Load	Base	No-Reverse	July	High_Load	12	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	3	PV System with ES	DER1	Reverse	August	Load_Load	14	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	4	ES – Peak Shaving	DER5	No-Reverse	September	High_Load	16	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	1	PV System, ES, and Load Control	Base	Reverse	October	Load_Load	19	5	2.5	7	1	1
Urban DPA	Camden 66/12 kV	Solitaire	2	PV System, ES, Load Control, and EVs	DER1	No-Reverse	November	High_Load	22	5	2.5	7	1	1

Figure 90: Sample Format for ICA Result Table

DER Profiles

Provided that the ICAWG agreed to created results that were agnostic and not specific and predefined by DER shapes these shapes are no longer necessary to provide.

7.b.iii Load Profiles

The complete Demo A data set includes the load profiles at DPA, substation, and circuit levels. Figure 8 shows a sample data table of load profiles.

Asset Name	Asset Type	Month	Load Day	Hour	Loading (MVA)
Urban DPA	DPA	Janurary	High_Load	1	72.19
Urban DPA	DPA	Janurary	High_Load	2	62.91
Urban DPA	DPA	Janurary	High_Load	3	74.20
Urban DPA	DPA	Janurary	High_Load	4	59.90
Urban DPA	DPA	Janurary	High_Load	5	61.57
Urban DPA	DPA	Janurary	High_Load	6	66.94
Urban DPA	DPA	Janurary	High_Load	7	78.22
Urban DPA	DPA	Janurary	High_Load	8	86.38
Urban DPA	DPA	Februrary	Low_Load	9	90.74
Urban DPA	DPA	March	High_Load	10	94.54
Urban DPA	DPA	April	Low_Load	11	99.12
Urban DPA	DPA	May	High_Load	12	99.12
Camden	Substation	June	Low_Load	13	24.53
Camden	Substation	July	High_Load	14	24.19
Camden	Substation	August	Low_Load	15	24.19
Camden	Substation	September	High_Load	16	24.14
Solitaire	Circuits	October	Low_Load	17	5.05
Solitaire	Circuits	November	High_Load	18	5.53
Solitaire	Circuits	December	Low_Load	19	5.53
Solitaire	Circuits	Janurary	High_Load	20	5.45
Solitaire	Circuits	Februrary	Low_Load	21	5.32
Solitaire	Circuits	March	High_Load	22	5.12
Solitaire	Circuits	April	Low_Load	23	4.67
Solitaire	Circuits	May	High_Load	24	3.93
Solitaire	Circuits	June	Low_Load	1	5.57
Solitaire	Circuits	July	High_Load	2	5.51

Figure 91: Sample Format for Load Profiles

7.b.iv General Information

The complete Demo A data set also includes the general system information such as customer type breakdown and existing generations at the circuit level. Figure 9 and 10 show the sample data table for DPA/substation level and circuit level, respectively.

Asset Name	Asset Type	Voltage (kV)
Urban DPA	DPA	66
Rural DPA	DPA	66
Camden 66/12 kV	Substation	12
Octol 66/12 kV	Substation	12
Tulare 66/12 kV	Substation	12

Figure 92: Sample Format for DPA/Substation General Information

Asset Name	Asset Type	Voltage (kV)	Res Cust (%)	Comm Cust (%)	Ind Cust (%)	Agr Cust (%)	Conn Gen Cap (MW)	Queued Gen Cap (MW)	Total Gen (MW)
Solitaire	Circuit	12	50	20	10	20	1.02	2.00	3.02
Alloy	Circuit	12	50	20	10	20	0.50	0.50	1.00
Bingo	Circuit	12	50	20	10	20	1.60	0.00	1.60
Faro	Circuit	12	50	20	10	20	0.86	0.60	1.46

Figure 93: Sample Format for Circuit General Information

7.c Process for Updating Analysis

The toolsets and processes for evaluating ICA have been developed to work within the main tools of LoadSEER and CYMDIST. This was important to get closer to the level of automation necessary to provide regular updates. A final process can't be provided since the final approval and approach has not been ruled upon. That being said PG&E recommends that the updates be required no shorter than a month. This aligns with the refresh time of the public queue and the RAM map. PG&E believe this to be achievable with the streamlined approach, but if the iterative approach is required for this publication then a longer time period is desired. Full analysis and awareness of the processing is not known and a recommendation on timing with iterative can't be provided.

PG&E is still in the process of consolidating and finalizing the result set for publication and visualization on the maps. PG&E will notify the ICAWG and CPUC when final datasets are ready to be shared. It is expected that they will be ready in January.

8 ADDITIONAL STUDIES

8.a Smart Inverter Functionalities

8.a.i General Approach

Additional analysis was included in order to start understanding the impact of smart inverters on ICA when they become a standard of interconnection in 2017. One of the biggest impacts projected is the use of reactive power capabilities to reduce voltage impacts. PG&E conducted a focused analysis of reactive capabilities within the streamlined methods on a long feeder within the Chico DPA. This feeder has about 60% of its nodes limited by voltage and appeared to be a good candidate for the analysis.

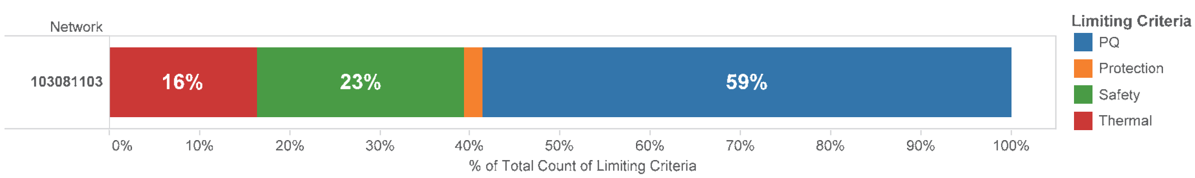


Figure 94: Limiting Criteria for Butte Feeder

The streamlined equations have a power factor component in order to do these more advanced analyses. The following discusses the method used implement power factor adjustment in the models.

Study Methodology

1. Provide ability to set power factor of DER
2. The power factor can be set based on EPRI' s method[11]

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[11] Analysis to Inform CA Grid Integration: Methods and Default Settings to Effectively Use Advanced Inverter Functions in the Distribution System. EPRI, Palo Alto, CA: 2015. 3002007139

1) Baseline (M0) – Unity Power Factor
2) Method 1 (M1) – Median Feeder (X/R) Ratio
    i. $Power\ Factor \cong \frac{\left(X/_R\right)_{median}}{\sqrt{\left(X/_R\right)^2_{median}+1}}$
3) Method 2 (M2) – Weighted Average X/R Ratio[12]
    i. Calculate the DER size weighted average X/R.
    ii. Calculate power factor by applying the X/R ratio calculated in step 1 in the power factor setting formula for single DER system. If the calculated power factor setting is below 0.9, set it to 0.9. (Negative sign denotes inductivevar)[13]

The time constraints within Demo A as well as limited flexibility in the CYME ICA module did not allow PG&E to perform additional analysis on the iterative method. CYME does have the capability to simulate Volt/VAr, but does not provide this specific adjustment within the ICA module. More benchmarking and research will be needed to determine best methods to incorporating into iterative approaches.

8.a.ii Results and Findings

The findings have shown that overall there is an increase in the PQ IC when considering these power factor methods. Most of the increase is when the DER is electrically closer to the substation while further out the difference is reduced significantly.

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[12] Step 3 for method 2 was ignored since we were not evaluating a specific size, but finding a size that would create a 3% deviation than step 3 is not applicable.

[13] Values were limited to no more than 20MW due to the optimization to determine a zero in the denominator of the IC equations. This can produce impractically large values if not done.

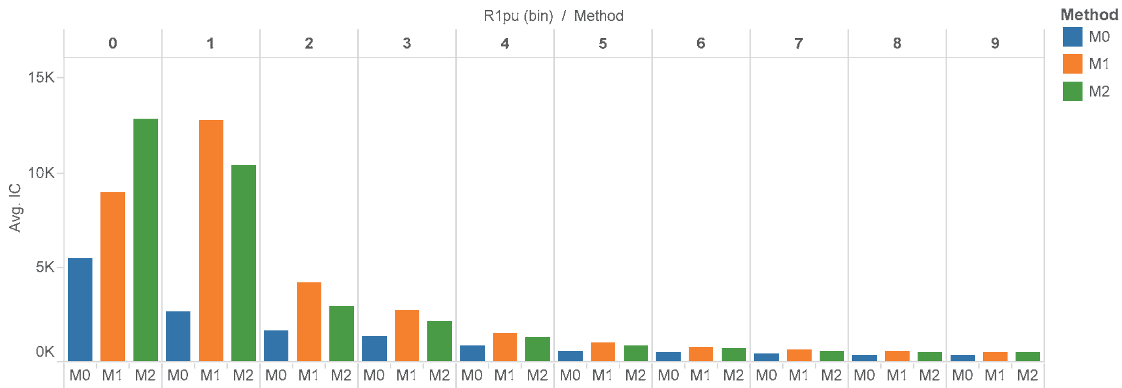


Figure 95: Average Steady State IC across PF Methods

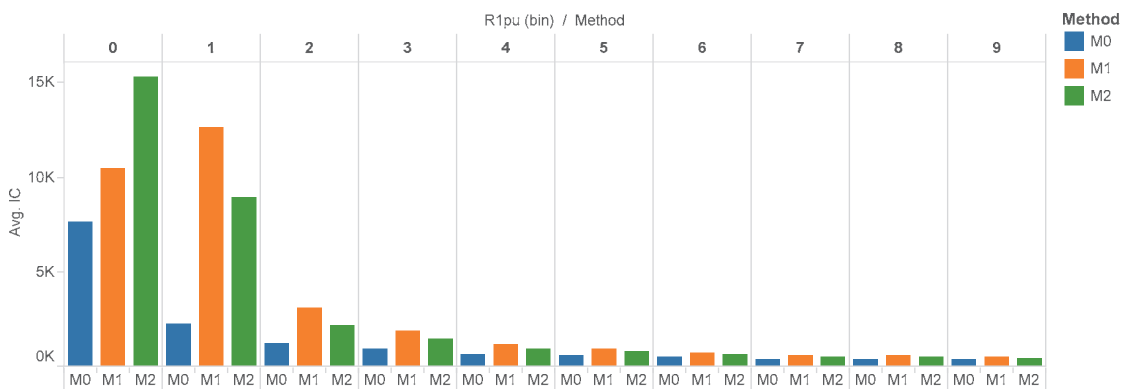


Figure 96: Average Voltage Variation IC across PF Methods

This trend can also be seen by evaluating the scatter plots for each method across all nodes. In general there are significant increases in IC closer to the substation. This is mainly due to the lower impedances which create a stiffer connection that makes it harder for the DER to adjust system voltage.

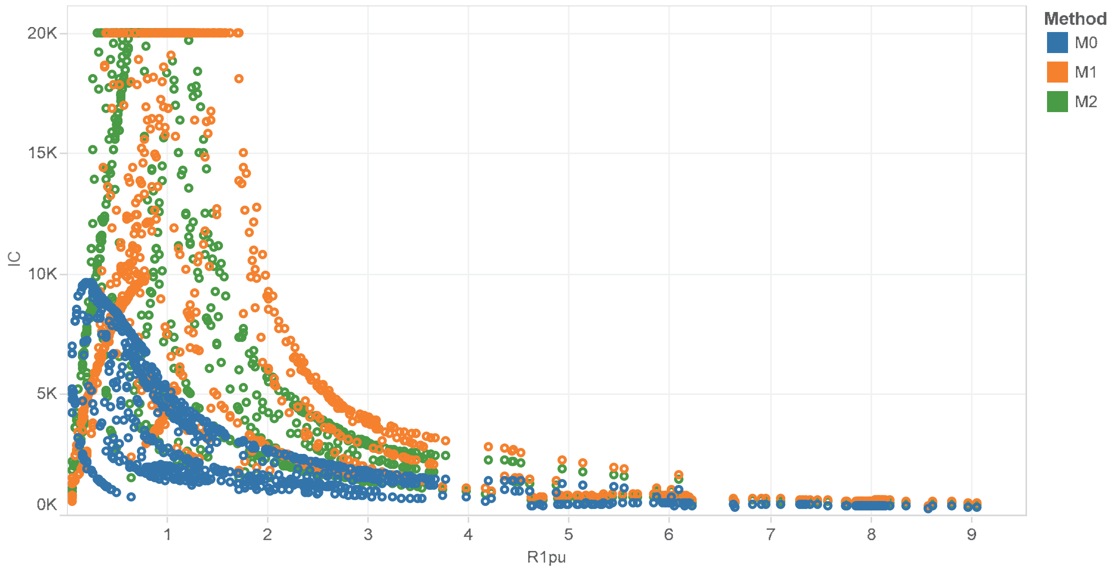


Figure 97: Steady State IC at each Node across PF Methods

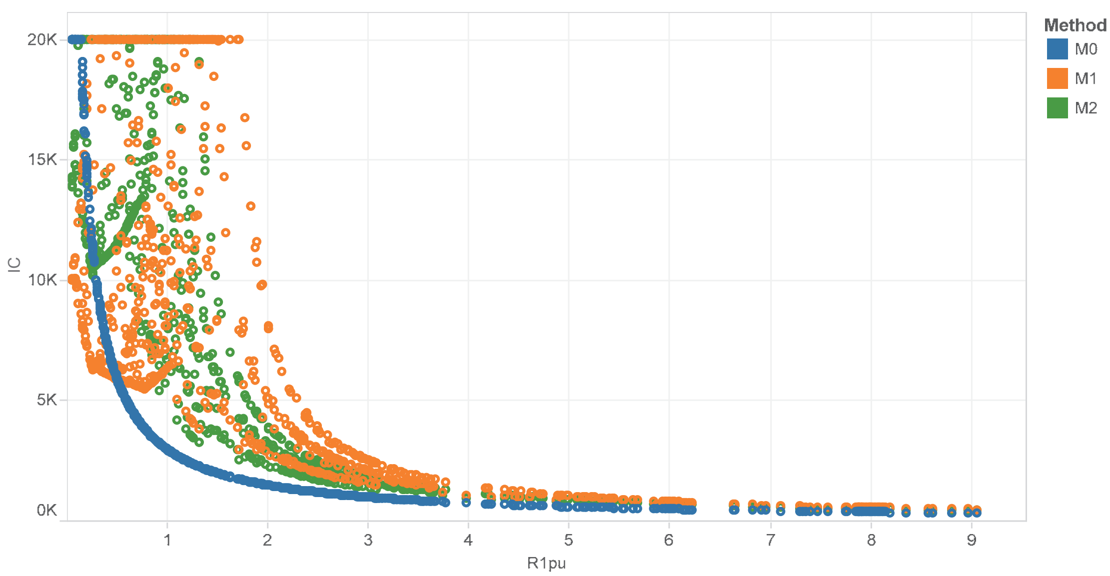


Figure 98: Voltage Variation IC at each Node across PF Methods

When evaluating Figure 97 and Figure 98, it can be seen that right near the substation there are some nodes in which IC seems to have reduced. Box plots were then used to see the extent of this. These can be seen in Figure 99 and Figure 100. This observance of decreased IC is in line with EPRI’ s determination that Power Factor should be kept at unity closer to the substation. It is expected that these large numbers so close to the substation could create large disturbances in the reactive power flow when off unity as well.

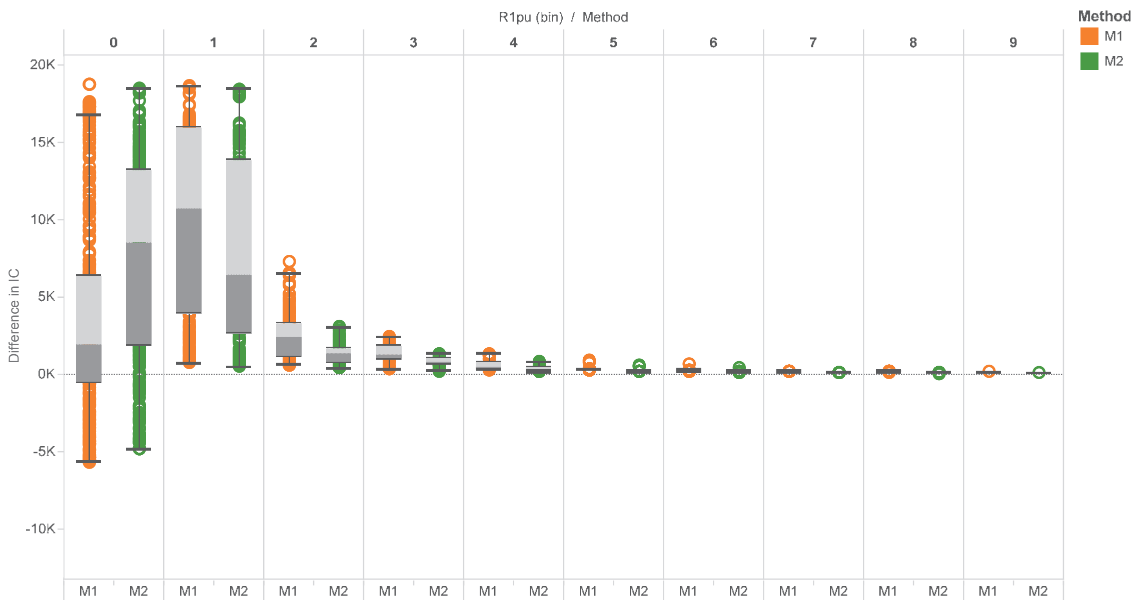


Figure 99: Boxplot of Steady State IC Difference from Baseline for Each New Method

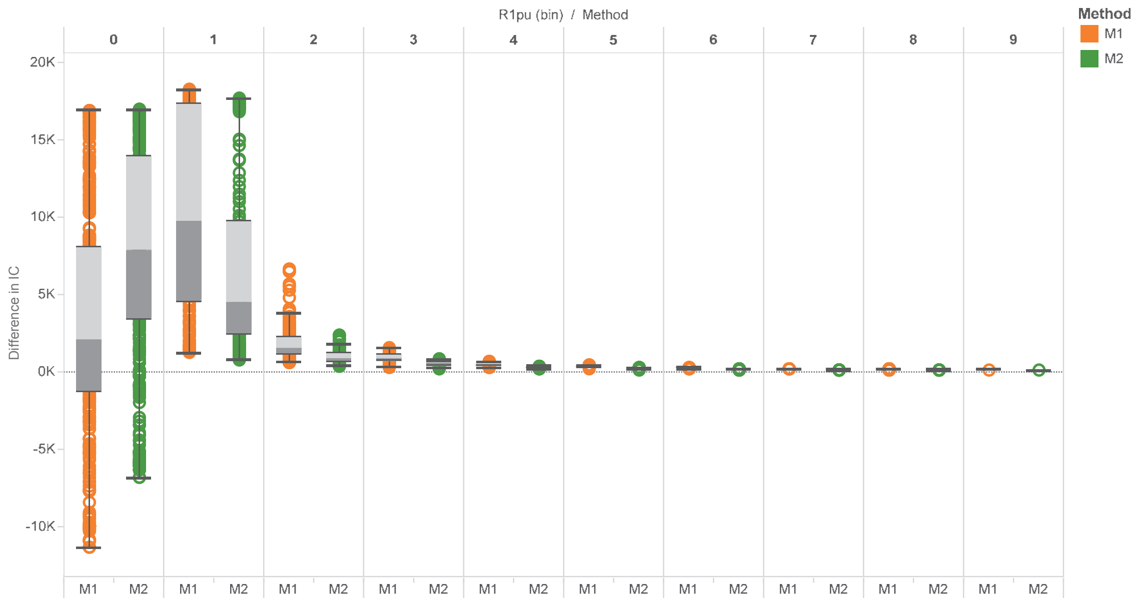


Figure 100: Boxplot of Voltage Variation IC Difference from Baseline for Each New Method

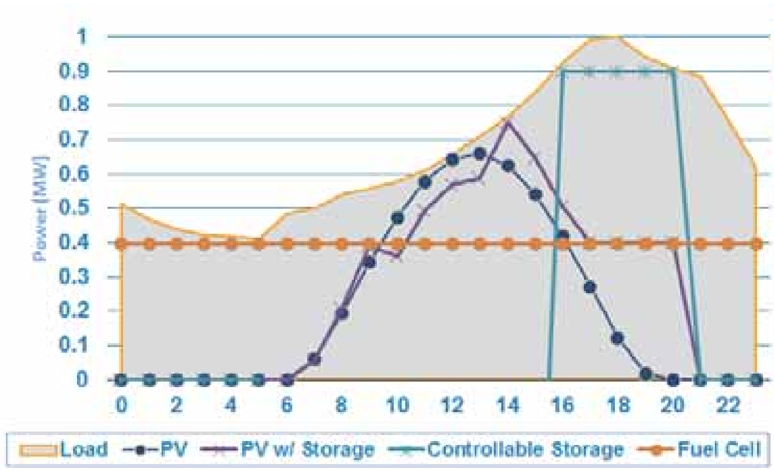
Overall it can be seen that using power factors off unity can help decrease the impact on voltage and thus increasing the PQ IC. It is also seen that the effect is different depending where on the circuit it is placed and which method is used. More research and evaluation will be needed due to the different methods and evolving discussions around default settings. These methods can be incorporated into the methodology if default settings similar to this will be applied in a standard manner across all feeders. More discussion will be needed for proper inclusion in the methodology if decisions around settings will be more dynamic and flexible based on specific conditions of the circuit.

Another factor to consider for further exploration and analysis is the reactive power demand and impact on the system. While voltage impacts were measured, the reactive power demands were not evaluated for their impact as well. This should be scoped for further analysis.

8.b DER Portfolio

8.b.i General Approach

For the initial DRP, PG&E uses specific hour-by-hour DER profiles to analyze Integration Capacity. The level of impact to the system is different for DERs with different output profiles. Figure 101 below depicts how different DER could have different integration capacity limitations by comparing the DER output and how it coincides with a load profile. While the hosting capacity can be affected by many factors this figure isolates visuals to just reverse flow penetration for ease of discussion. This figure shows that, depending on the DER, there are different hours when the limit is occurring and that it produces different capacity limitations.



DER	Limiting Hour	Max Capacity
PV	12 PM	0.66 MW
PV w/ Storage	2 PM	0.75 MW
Controllable Storage	4 PM	0.90 MW
Fuel Cell	5 AM	0.40 MW

Figure 101: DER Limits Depend on Profile Shapes

The earlier discussions on ICA from stakeholder engagement and CPUC workshops revealed a great opportunity to better understand the broader application to various DERs and portfolios. This was to expand the results to not just provide the most limiting value, but to expand the results to be hourly and expose the various limits within each category. Figure 102 depicts what the example output would be for a particular location. This would be in contrast to just providing the most limiting value which in this case would be around 250kW.

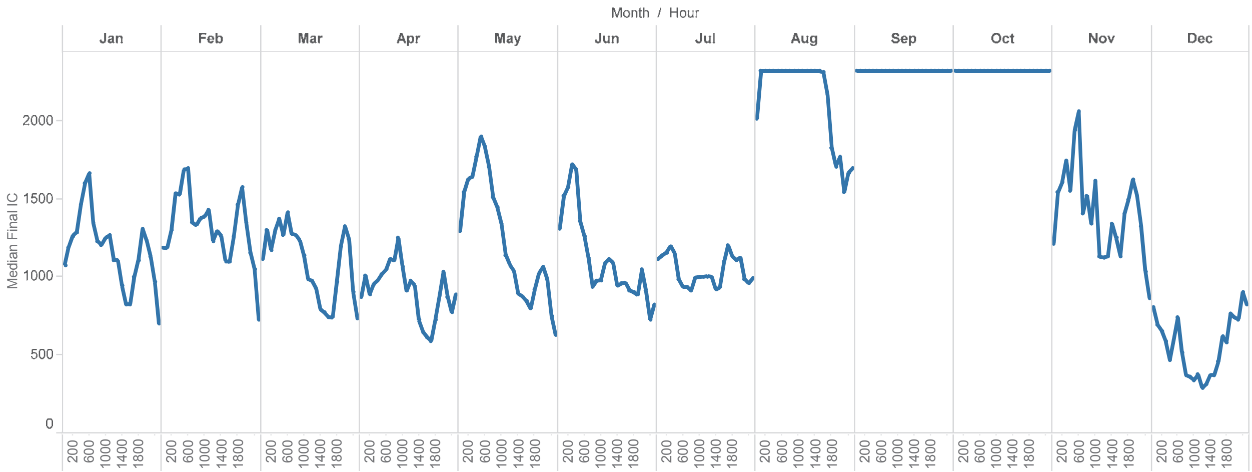


Figure 102: Example Hourly ICA Profile at a Node

In order to streamline the analysis, the IOUs explored utilizing the hourly results in a manner that would not require additional analyses to be performed for each DER type. Figure 103 below is an attempt to visualize how this concept is applied. The hourly output profile of the DER is evaluated against the hourly ICA profile.

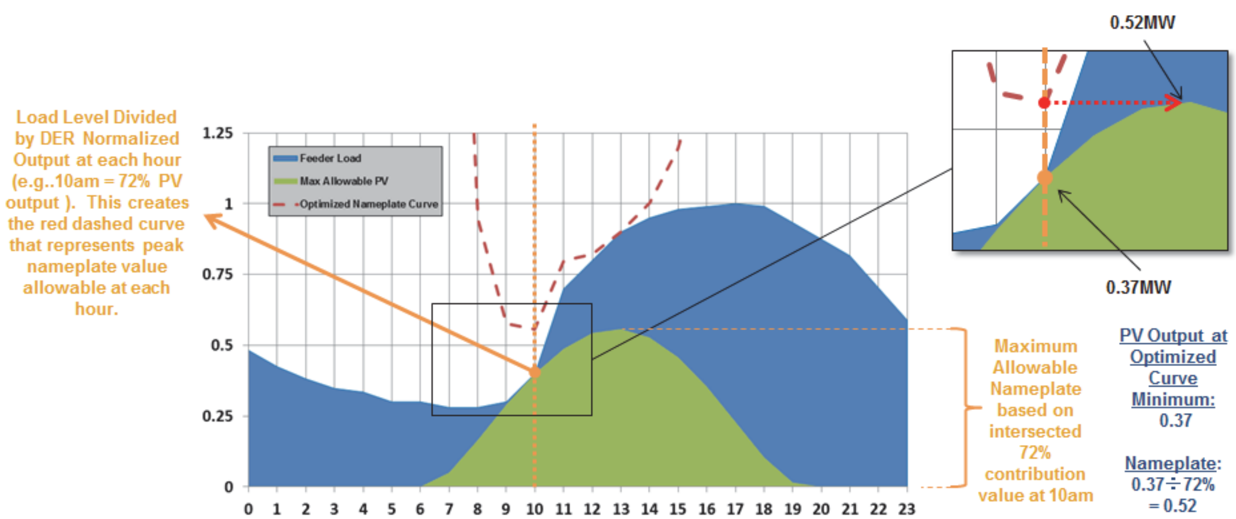


Figure 103: Visual Diagram of Extracting DER Specific Values from Hourly ICA

Figure 103 depicts that given an ICA profile, there exists a PV power profile with values smaller than the load for the entire observed time interval except for one specific time where the profiles intersect. This specific PV curve has the highest nameplate capacity possible while satisfying the criterion of not surpassing the ICA limit at any time.

The DER specific limit needs to be related to nameplate. Given a normalized DER profile and hourly capacity limits, an optimized curve can be created by relating the ICA profile to the normalized DER profile. This method is similar to how PG&E established DER specific capacities for the 2015 DRP filing. The method can be expressed in mathematical terms as follows:

$$\text{Nameplate Capacity Curve} = \text{F} = \frac{\text{ICA[t]}}{\text{DER}_{\text{pu}}\text{[t]}}$$

$$\text{Limiting Capacity for Specific DER} = \min_{t \in \mathbb{R}}(\text{F})$$

Figure 104 depicts how this can be applied to various DER profiles given one ICA profile.

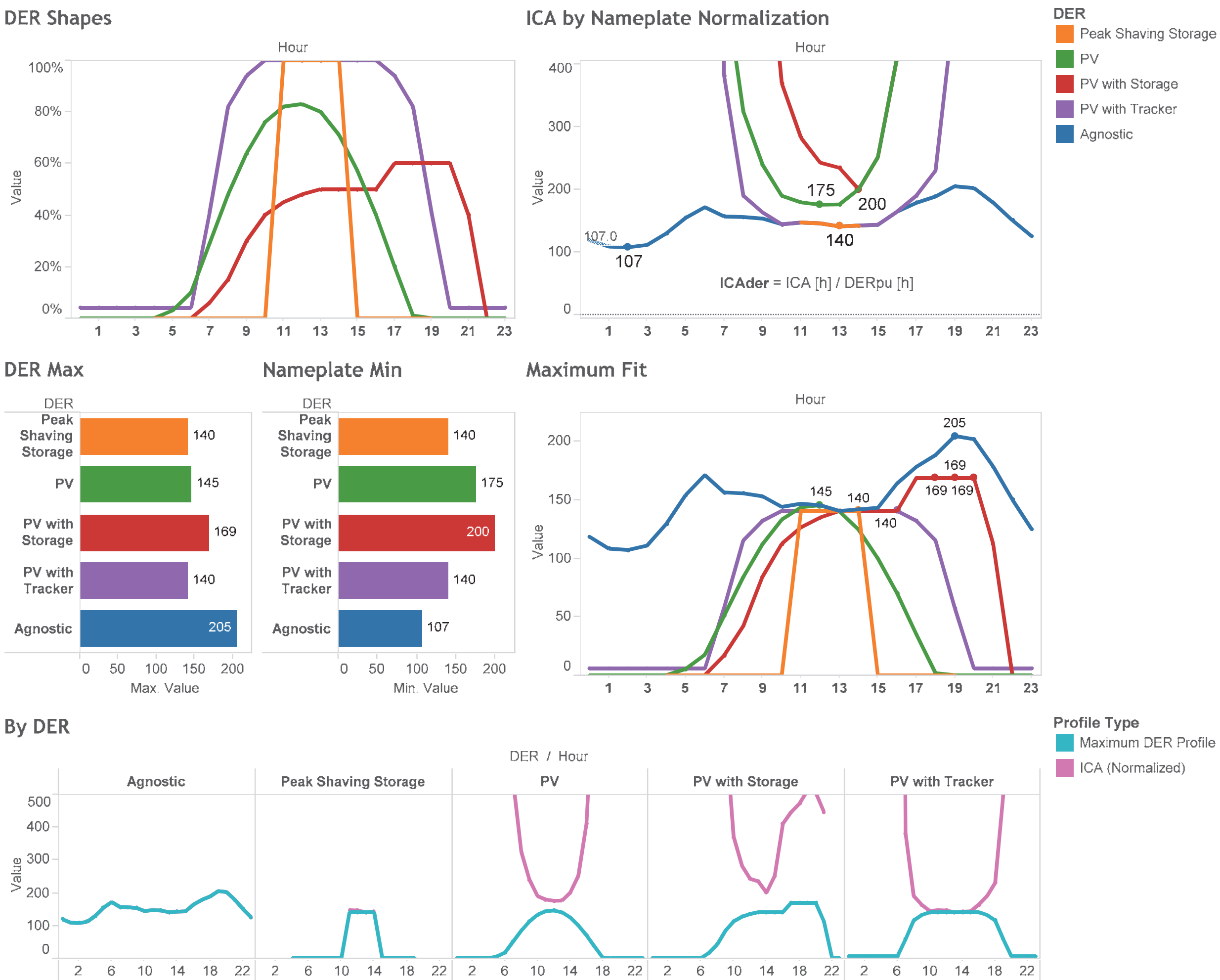


Figure 104: DER Specific Results from Hourly ICA Profile

8.b.ii Results

The following figures explore the relationship of IC to distance versus time. The purpose is to gain insight into the relationship of ICA variation due to distance versus time. The main take away from the figures is that distance has a much greater impact on ICA than time. Some variations occur throughout the day with load based on the loading scenario, but the main driver in ICA is the distance from the substation.

The figures are broken up by DPA and show comparison of distance to months and distance to hour of day. Figure 105 and Figure 106 show the relationship of

ICA on distance and months. Figure 107 and Figure 108 show the relationship of ICA on distance to hours.

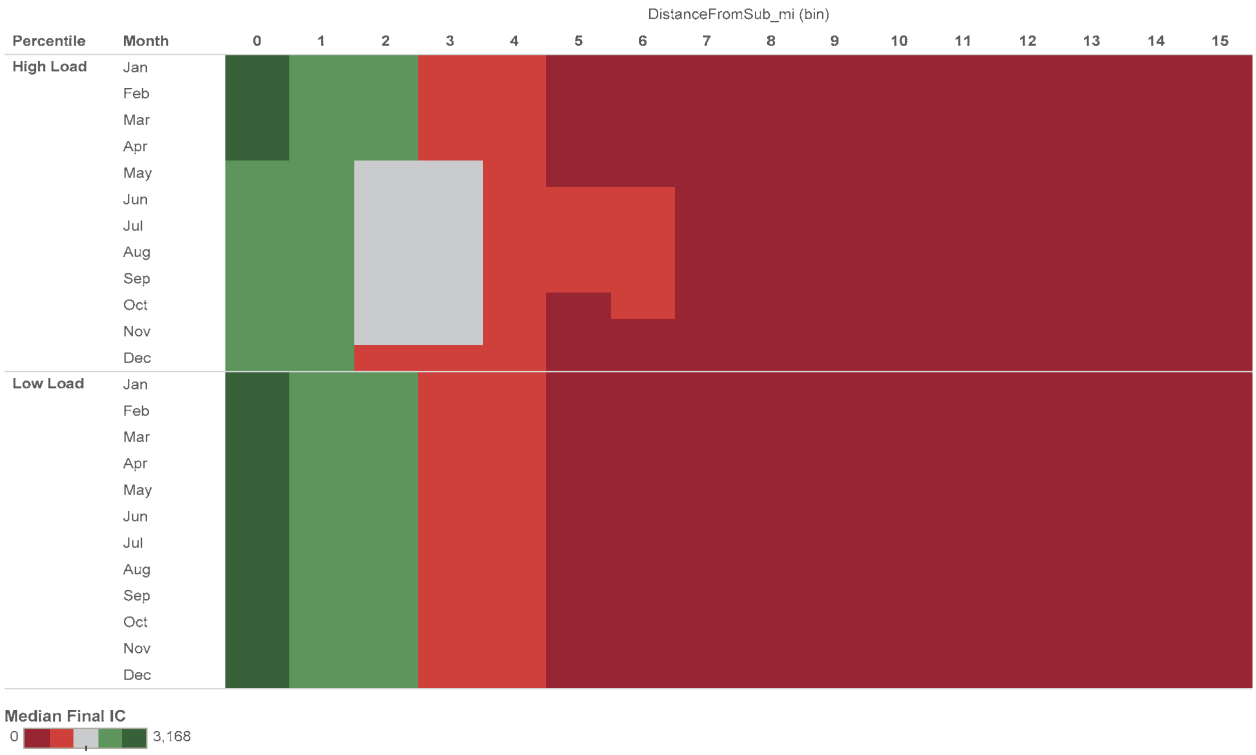


Figure 105: Heat Map of Median IC across Distance and Months (Chico)

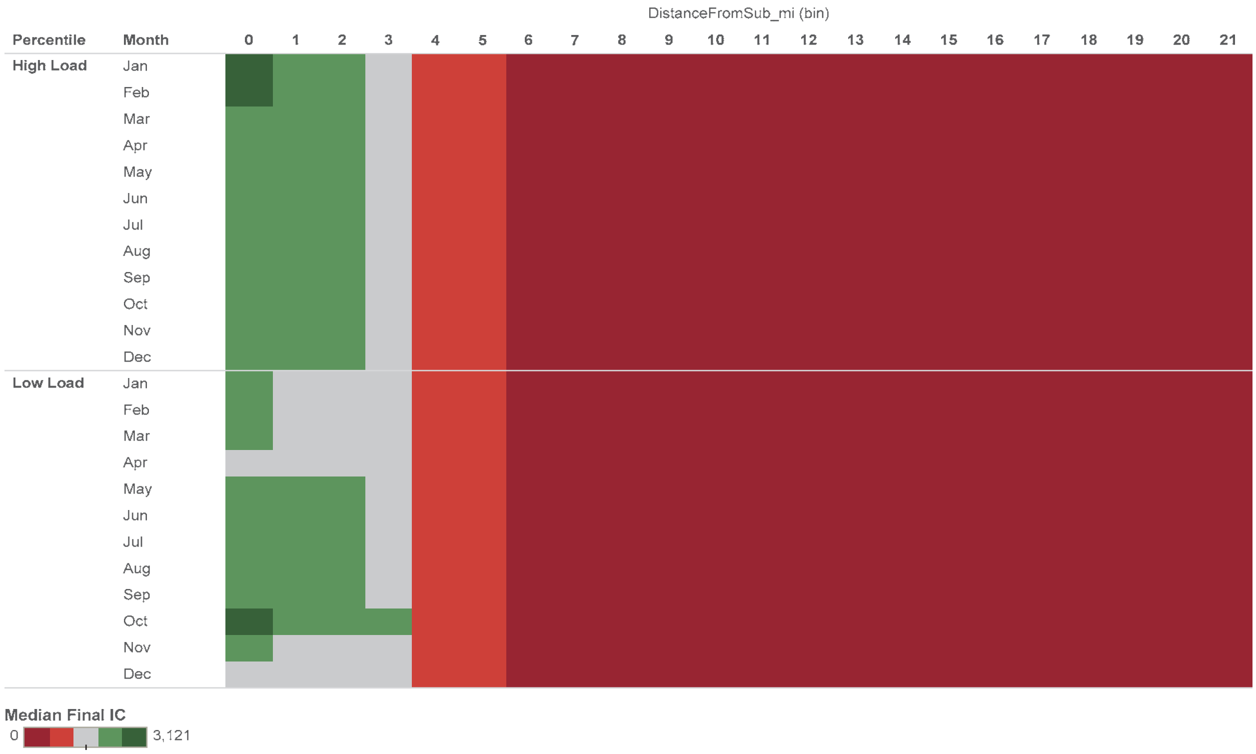


Figure 106: Heat Map of Median IC across Distance and Months (Chowchilla)

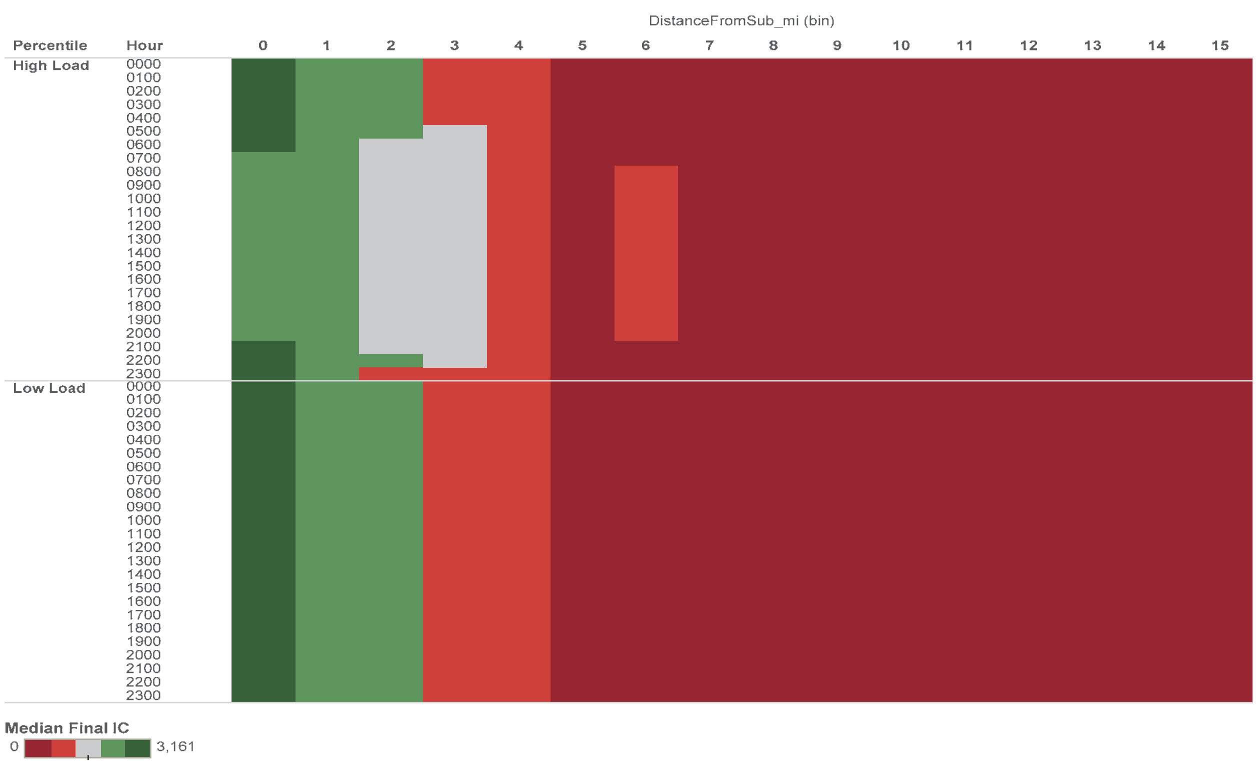


Figure 107: Heat Map of Median IC across Distance and Hours (Chico)

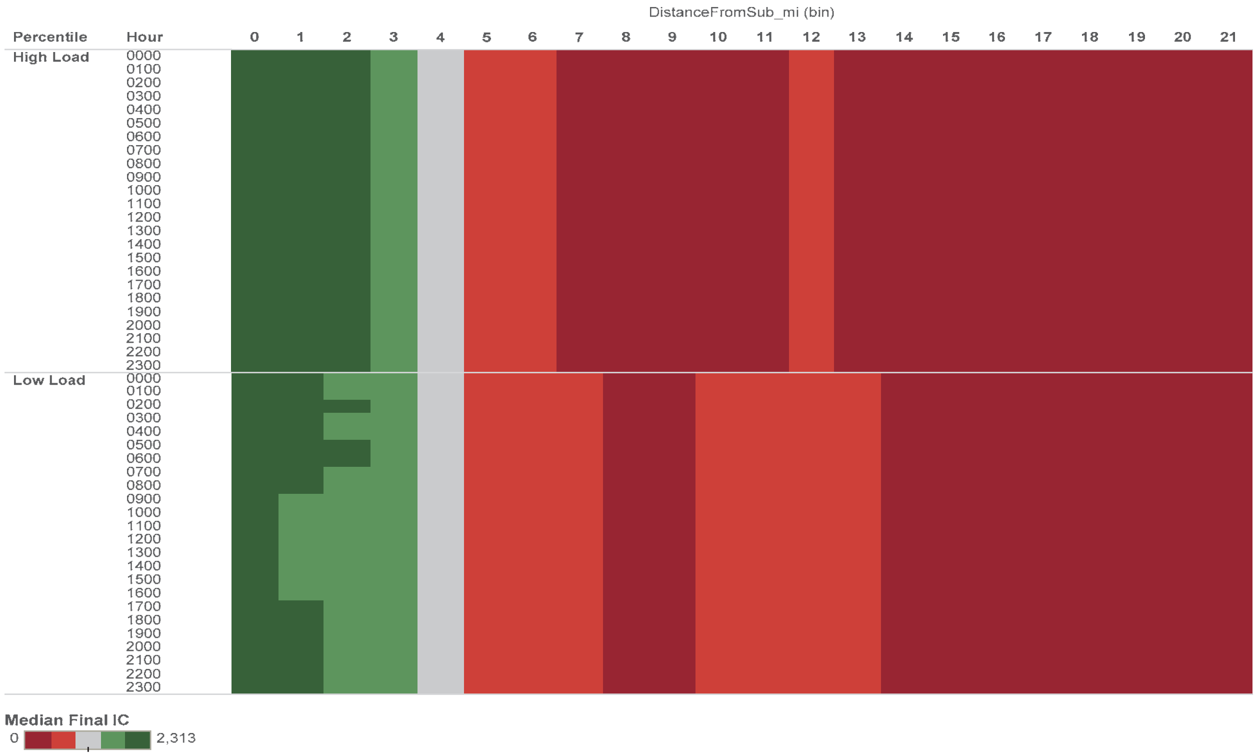


Figure 108: Heat Map of Median IC across Distance and Hours (Chowchilla)

9 DEMO A LEARNINGS

This chapter focuses on discussing some the learnings obtained from exploring multiple techniques in evaluating integration capacity across the areas selected for Demo A. Discussion will first summarize the learnings as relating to core objectives and then go into detail on specific topics. The following is a list of specific objectives within Demo A and learnings around those objectives.

1. **Reverse Flow Limitation**
    - PG&E implemented criteria of Operational Flexibility and transmission Penetration in which certain devices (SCADA operated switch points) limited all downstream nodes by its loading. By turning this off, ICA can be significantly increased in select locations, but the majority of locations are limited to 1-2MW increase. These larger increases are also heavily focuses to locations near the substation.
    - No learnings on the feasibility of this can be provided since transmission issues can't be determined and abnormal configurations aren't being analyzed. More work needs to be performed on (1) knowing TX limitations and (2) methods to determine issues for abnormal configuration.
    - Some reverse flow criteria are not based in heuristics, but create actual issues when subjected to such conditions. Main equipment that this is true for is voltage regulators. Voltage regulators having specific settings given conditions and forward flow assumptions. Controls and/or settings must be updated for regulators that were not designed to operate with reverse flow from DER.

2. **DER Growth and Forecast**
    - After research of other hosting capacity tools, the current form of ICA is lacking the ability to evaluate dispersed DER growth dependently to understand aggregate impact. This is important for understanding future DER growth. Current methods utilized modifications to feeder load shapes based on DER growth and used techniques better suited for large centralized DER.

3. **DER Portfolios and New Technology**
    - Hourly ICA results help to determine a more agnostic ICA. The hourly results may help in understanding certain shapes and characteristics to optimize DER on certain feeders.
    - Smart Inverters effects can be applied within streamlined, but limitations within the iterative approach would require more software development to incorporate in an automated approach.
    - EPRI power factor methods for smart inverters can be useful in helping reduce voltage impacts on the feeder, but standardization of default settings and application would be needed before implementing within ICA.

4. **Maps and Outputs**
    - Hourly results for every node is very difficult to manage and visualize
    - Result sets create a very large file size of data. Discussion and exploration of reducing this dataset is recommended.

5. Computational Efficiency

- PG&E cloud computing reduced average power flow times, but increased IT requirements and complexities. This is very helpful when analyzing thousands of feeders, but may not be necessary for small number of feeders and/or less hours to compute.
- Iterative computations are very slow when performing across many feeders, hours, and scenarios. Technique does not lend itself well to "what-if" scenarios.

6. Comparative Analysis

- IOUs can and have gained much consistency on baselining against a reference model to compare. While the IEEE 123 test feeder was useful for initial alignment, a more representative CA feeder is desired for continued comparison and validation.
- Running many hours of power flows can lead to simulations that do not converge to solutions. The risk of this increases with iterative given additional amount of power flow simulations needed compared to streamlined.
- PG&E found that the specific technique of iterative did not lend itself well to solving batch analyses on the complex circuits. Current form of iterative technique may be more accurate in determining power flow conditions than streamlined, but very rigid in evaluation of IC. It can give false negatives due to extraneous conditions on the circuit.

7. Locational Load Shapes

- Using smart meter data helps provide more granular data points to allow for more confidence in the load allocation, especially across different hours.

8. Future Roadmap

- PG&E learned that there are many complications in iterative that would need to be worked out to be able to match the functionality of streamlined. Iterative would be much better applied to specific conditions within the interconnection process, but not to an overall analysis for the whole system.
- PG&E will need to ensure the IT requirements are met to ensure proper solution going forward. Some of the requirements are already being met with improvements to the existing toolsets, but they may need some additional investment to support final capability required by the final decision.
- Hourly results can be helpful, but in general there is a much higher dependence of IC on distance and location rather than time. A priority should focus on ensuring optimization on locational dimensions before optimizing on temporal dimensions.

9.a Computational Efficiency

The PG&E streamlined ICA calculations use a combination of software developed by CYME and Integral Analytics. Processing times are significantly dependent upon the number of circuit line section\nodes and the number of loading conditions. PG&E set general processing time requirements and goals, such that all distribution circuits in the PG&E CYME and LoadSEER database(s) can be processed within 48 hours. CYME and Integral Analytics have demonstrated the ability to scale their combined software horizontally and process all of PG&E circuits within an estimated 3 – 144 hours, depending on the number of computer processors. CYME and Integral Analytics continue to collaborate in order to reduce processing times further.

The PG&E iterative ICA calculations use a combination of software developed by CYME and Integral Analytics. Processing times are significantly dependent upon the number of circuit line section\nodes and the number of loading conditions. By design, the iterative calculations require 10-100x more processing time compared to the streamline calculations, and are significantly dependent upon the number of circuit line section\nodes and the number of loading conditions, as well as the tolerance (KW). PG&E is currently using a tolerance of 250 KW within the CYME module. CYME and Integral Analytics have demonstrated the ability to scale their combined software horizontally and process all of PG&E circuits within an estimated 48 – 1000 hours. CYME and Integral Analytics continue to collaborate in order to reduce processing times further.

A key component to all this was the computing power utilized in order to achieve efficiency. PG&E desired an approach that was not utilizing the standard GUI desktop version of CYME. The goal was to utilize more server side components of the tools. Demo A used a combination of local machines and servers which relied upon many parallel computing streams for the analysis[14]. This also meant

[14] Specs of the machine(s):
Processor: 4 Core @ 4.00GHz
Installed memory (RAM): 32 GB

that multiple licenses for running the CYME software was necessary to achieve such speed running in parallel. While this showed much positive progress, it is at the cost of obtaining additional licenses for the tools and computing power. PG&E will look to see what can effectively be incorporated into the existing IT infrastructure for the planning toolsets, but likely there will need to be additional costs to fully implement.

9.b Consistency between methods

It was the original intent to use iterative as a baseline to compare streamlined against. However, after exploration of this technique it was noticed that it is not that straight forward. There are some limitations to the iterative technique that may provide accurate power flow results, but limit the ability to understand and create concise hosting capacity results. For instance, the iterative approach is very restrictive on limitations based on its interaction on the whole circuit. Iterative IC can be declared 0 for issues not relating to the new DER. In some cases this is preferred in order to understand the broader effect of the DER. In other cases existing conditions could create a limitation on ICA that shouldn't apply to that DER at that location.

Other nuances in the structure of the calculations limited ability to separate out as necessary. For instance the voltage regulator impact in streamlined was not analyzed separately from reverse flow in general. This was a feature of the iterative module within CYMDIST. Future work can explore further, but in general it provides a caution to blindly trusting iterative results as the baseline.

System type: 64-bit Operating System

As for the comparison between the utilities, there seem to be much progress in the aligning of methodologies. Reference circuits were helpful in providing testing and alignment. In general, specific implementation or nuances to the software tools may provide some deviations. In PG&E perspective there is a solid base to show that there are similarities in methods, but general improvement can always occur to improve on the methods and best path forward.

9.c ORA 12 Success Criteria

Office of Ratepayer Advocates (ORA) proposed 12 success metrics in the November 10, 2015 ICA workshop to evaluate ICA tools, methodologies, and results. These metrics are:

1. Accurate and meaningful results
    a. Meaningful scenarios
    b. Reasonable technology assumptions
    c. Accurate inputs (i.e. load and DER profiles)
    d. Reasonable tests (i.e. voltage flicker)
    e. Reasonable test criteria (i.e. 3% flicker allowed)
    f. Tests and analysis performed consistently using proven tools, or vetted methodology
    g. Meaningful result metrics provided in useful formats
2. Transparent methodology
3. Uniform process that is consistently applied
4. Complete coverage of service territory
5. Useful formats for results
6. Consistent with industry, state, and federal standards
7. Accommodates portfolios of DER on one feeder
8. Reasonable resolution (a) spatial, (b) temporal

9. Easy to update based on improved and approved changes in methodology
10. Easy to update based on changes in inputs (loads, DER portfolio, DER penetration, circuit changes, assumptions, etc.)
11. Consistent methodologies across large IOUs
12. Methodology accommodates variations in local distribution system, such that case by case or distribution planning area (DPA) specific modifications are not needed

PG&E evaluated these 12 recommended success metrics in the Demo A implementation. The following list describes how Demo A meets or exceeds each of these metrics, and where areas of improvement may be possible.

1) **Accurate and meaningful results**
   a) **Meaningful scenarios**
      Demo A conducted ICA studies under many scenarios to understand the DER capacity while maintaining safety, reliability and operational flexibility. These scenarios include many different hours throughout the year (288), different loading conditions (high and low), with and without reverse flow restrictions, three different DER growth scenarios, and two years of load growth. All these add up to 10,368 scenarios to obtain varying aspects of knowledge around ICA.

      The Integration Capacity values for inverter based uniform generation and uniform load are produced in Demo A. With the provided ICA translator, stakeholders are able to develop customized Integration Capacities for any DER types or DER portfolios. Due to the variations in geographic locations, manufacturer configurations and developer designs, the same DER type or portfolio may have different output profile, DER technology agnostic ICA values can not only provide flexibility for stakeholders to evaluate a broad array of DER technologies but also avoid misleading information.

b) Reasonable technology assumptions

ICA methodologies and assumptions have been developed based on engineering principles and practices which are commonly applied and used in the engineering industry. These assumptions include the utilization of power flow to determine limiting factors such as thermal and voltage limits, the utilization of American National Standard (ANSI) C84.1 - 2011 Range A as guiding principle for voltage fluctuation limits, the assumption on short circuit duty contribution for DER and the utilization of tariffs and standard such Rule 21 and IEEE1741/UL1547 among others.

One area where there is need for continued improvement includes adequate modeling of smart inverters, advances in operational flexibility limitations and advanced in reactive power group control mechanisms (such as Distribution-Volt-Var system control). Given the time required to complete Demo A and the lack of fundamental modeling techniques for these areas, Demo A was not able to complete this level of analysis but the IOUs see a tremendous opportunity to continue improvement of ICA in this areas.

c) Accurate inputs (i.e. load and DER profiles)

IOUs developed and validated circuit models based on up-to-date system configuration and leveraged load forecasting tool/algorithm, SCADA data and DER forecasts. Customer loads were also more accurately allocated on an hourly basis from AMI data. All these efforts aim to ensure the more accurate inputs which help provide more accurate ICA results.

The Track 3 efforts underway will help to improve the DER forecasts that go into the circuit model, which should improve the accuracy of the circuit load forecast. The IOUs expect that these improved forecasts will be incorporated into future updates to the ICA.

d) **Reasonable tests (i.e. voltage flicker)**

Industry standard tests are included in Demo A to determine the DER Integration Capacity of the distribution system. These tests are deemed necessary for DER screening or interconnection analysis and are consistent with IOUs' engineering, planning and protection standards. The criteria has also been deemed reasonable and necessary based on knowledge of system design and operating practices.

e) **Reasonable test criteria (i.e. 3% flicker allowed)**

The power system criteria adopted in Demo A are consistent with industry standard criteria (e.g., thermal criterion), electric service rules (e.g., steady state voltage criterion and protection criterion), and IEEE recommended practices (e.g., voltage fluctuation criterion). In addition, these criteria align with IOUs' system design and operating standards.

For example, the voltage range used for steady state voltage aligns with ANSI Range A. The flicker criterion is determined from each utility's engineering standards and/or industry recommended limits. Thermal criteria used are the equipment ratings as established by the manufacturer and/or each utility's engineering standards.

f) Tests and analysis performed consistently using proven tools, or vetted methodology

Industry standard power flow tools such as CYMDIST are used in the Demo A to evaluate the system conditions under various DER interconnection levels. The ICA methodologies are also synchronized among IOUs based on the comparative assessment efforts to ensure a more consistent ICA process.

It is also recognized that the methodology, tools, and capabilities are evolving with the need to understand DER's effects in high penetration. Tools and software still need improvement and development as the industry determines a proper steady state condition for ICA and functionality to properly consider distributed DER. Benchmarking with other institutions and utilities will be necessary to ensure a proper vetted methodology. Validation and reference model work within the ICAWG will be helpful to promote this success criteria.

g) Meaningful result metrics provided in useful formats

The ICA results will be provided in both online map and downloadable data formats. The most practical and relevant scenario is displayed on the map while the complete data (i.e. 576 ICA for each main criteria) are provided in the downloadable files so that DER developers can query and retrieve relevant information. Both the online map and downloadable data are provided in sufficient details and in similar formats so that stakeholders can easily understand and utilize the information.

Once the ICA results are put to use, there may be improvements made to the output files based on input from stakeholders. To the extent that improvements are practical, the IOUs strive to provide effective results for stakeholders.

2) **Transparent methodology**

The details of the methodologies including equations, assumptions and thresholds are provided in the project reports. IOUs intend to coordinate with the ICAWG to also setup a standard set of circuits such as, but not limited to, the IEEE 123 test circuit with respective results to allow for validation and testing through external stakeholders.

3) **Uniform process that is consistently applied**

The ICA methodologies are consistent with the four-step baseline methodology outlined in the ACR. Automated python scrips have been designed to maintain the implementation batch processing of methodology consistent to all the circuits in demo A in order to minimize manual engineering implementation of the ICA calculations.

Many components of the analysis were geared to ensuring automation which include the load and forecast allocation, power flows, IC calculations, abstraction processing, and result output.

4) **Complete coverage of service territory**

As part of Demo A, IOUs implement and demonstrate the ICA methodology in two selected DPAs. Based on the Demo A learnings, improvements to the ICA methodology such as computational efficiency techniques are proposed for the ICA process to help cover the entire service territory. This effort will be supported by IOU activities such as CYME gateway to streamline circuit modeling creation and update.

Limitations to three phase line sections still apply, but discussion and exploration of single phase will be explored in the long term. It is also worth noting that the handful of network circuits that PG&E has are not included because there are not standard models in CYMDIST for them. Inclusion of these network circuits can be reviewed as ICA progresses and PG&E's tools and datasets improve. Otherwise there is a significant difference in the modeling required for the network circuits that would hinder general progress of ICA for the vast majority of radial distribution circuits.

5) **Useful formats for results**

The ICA results are to be published via online maps and downloadable data files. The most practical and relevant scenario is displayed on the map so that DER developers can navigate through circuit sections based on the visual presentation to identify the locational variance of the DER Integration Capacity. The downloadable data files contains all the ICA results so that DER developers can query information to perform specific studies in order to identify the optimal locations for certain DER or DER portfolios. Both maps and downloadable data files are designed in a similar style and are clearly explained through the inclusion of "keys" and documentations so that all California stakeholders can obtain similar data and visual aspects and can easily understand and utilize the information.

There may be room for improvement based on input from the ICAWG and other stakeholders. If certain functionalities are deemed critical to DER implementation, the IOUs can look to modify the maps in the future to accommodate new functionalities to the extent feasible.

6) **Consistent with industry, state, and federal standards**

The power system criteria adopted in Demo A adhere to industry, state, and federal standards. Thermal criteria are based on equipment ratings established by manufacturers and design criteria established in CPUC General Orders 95 and 128. Steady state voltage criteria is determined by IOUs’ Rule 2, which are drawn from American National Standard (ANSI) C84.1 - 2011 Range A. Transient voltage criteria align with IEEE recommended practice defined in IEEE Standard 1453-2015. Both protection and operational criteria are based on the EPRI hosting capacity methodology and align with IOU’s system design and operating standards as well as interconnection standards CA Electric Rule 21 and FERC Wholesale Distribution Tariff.

7) **Accommodates portfolios of DER on one feeder**

The increased granularity of results to each node as well as hourly results helps provide insight into location and temporal differences to help understand optimization of specific DER throughout a circuit.

An ICA translator along with the ICA results calculated for inverter-based uniform generation and uniform load DERs. This translator is designed to convert the technology agnostic ICA curves to any DER technologies or portfolios of DER technologies. Stakeholders can use this translator to generate the ICA values for their planned DER portfolios based on a customized DER output profile. This mechanism can provide the most representative ICA values for any DER technologies or DER portfolios comparing with ICA values based on typical DER profiles.

8) **Reasonable resolution (a) spatial, (b) temporal**

A very granular geospatial circuit model and hourly load profile is used to conduct the ICA. The IC is evaluated at all three phase nodes of each primary line section within individual distribution feeders including primary side of service transformers that feed customer premises. Demo A also adopts hourly power flow analysis to evaluate the nodal integration capacity for 24 hours a day, and two days for every month of the year covering both the peak and minimum loading conditions.

9) **Easy to update based on improved and approved changes in methodology**

IOUs have been steadily improving the ICA methodologies since the DRP plan filing in 2015 and through Demo A. The ICA also in part utilizes open scripting platforms within power flow tools to develop the automated batch process, but still have some dependence on the software developers ensuring proper capabilities to perform necessary tasks.

It should be noted that while the IOUs have strived to develop the ICA tools with future improvements in mind, care should be taken not to underestimate the time and resources required to implement further upgrades. Each increase to the capabilities of the ICA tools comes with a commensurate increase in time, cost, and engineering resources to achieve. In some cases, certain functionalities may not be possible until other foundational upgrades are in place. Much coordination has occurred with software vendors to ensure the tools had sufficient capabilities to perform necessary tasks. This coordination is ongoing and will need to continue as the methodology evolves.

10) Easy to update based on changes in inputs (loads, DER portfolio, DER penetration, circuit changes, assumptions, etc.)

The ICA methodologies are designed to facilitate changing various parameters to analyze different loading conditions and scenarios. In addition, various initiatives such as the integration of load forecasting tool with power flow tool and the streamlining of circuit modeling update from GIS database are underway across IOUs to enhance the flexibility of the ICA process.

As noted above, the IOUs have foreseen and accommodated some future improvements, but as with any new tool or process, there are unforeseen challenges that can and will arise as the tools evolve over time.

11) Consistent methodologies across large IOUs

IOUs worked closely to develop common ICA methodologies and processes including assumptions and power system criteria in order to ensure consistency. The adopted ICA methodologies are aligned with the baseline methodology described in the ACR. In addition, comparative assessment using IEEE 123 node test feeders are performed in order to further ensure that the application of the ICA methodologies such as power flow tool and model parameter configuration are also consistent among IOUs.

12) Methodology accommodates variations in local distribution system, such that case by case or distribution planning area (DPA) specific modifications are not needed

The ICA methodologies are based on fundamental circuit analysis functions and are designed for batch analysis which sufficient flexibility to address locational variance of system characteristics. The methodologies are able to be applied system wide without method customization or adjustment to accommodate difference throughout the distribution system.

While the methodology can handle these variations, more development and research will be necessary to determine best methods of incorporating future changes and variations within the distribution system as inputs to the models to be analyzed.

9.d Recommendations

9.d.i Initial Deployment (next 12 months)

Following the ICA studies exercised during Demo A, certain types of analyses are ripe for inclusion in the ICA process in the near term.

Application of Methodology

PG&E supports and recommends that the streamlined techniques focus on planning analysis in order to perform broader system analysis for more proactive awareness and scenario consideration. It is also recommended that the public maps use this technique as well to help reduce IT burden of regular updates.

PG&E has seen that the enhanced processing of the iterative method across all nodes at all hours is extremely onerous and a heavy IT burden. Application of this technique is better suited to more specific situations in which variables and scenarios can be significantly reduced. Utilizing for specific interconnection evaluation help provide this narrowing to which DER can be evaluated based on applications and modes of operation. In this sense iterative would be used in a focused manner to speed up detailed interconnection studies. More automated approaches to integrating these tools with the interconnection portals could be helpful.

PG&E is already in the process of integrating its internal workflow tools and SNEM portal with the CYMDIST toolset and its server functionalities. Utilizing these initial integration efforts, it can be explored long-term on how to get more on demand iterative ICA evaluations based on specific applications. This would be a more feasible application of the iterative method to enhance interconnection studies and reduce unnecessary detailed iterative evaluation at locations where DER is not being interconnected.

Interconnection Screens

More specific use of the iterative method and/or module within CYME could help streamline Fast Track studies and improve the outdated methods such as the 15% rule in screen M. The short circuit contribution ratio in screen F could also be evaluated for replacement with inclusion of iterative evaluations of protection device reduction of reach. However, further review of this module and application to the screen would be desired with PG&E protection department.

If more dependence on these advanced analytics is put in place for interconnection then the additional IT infrastructure and software licensing will need to be assessed and evaluated. This would be necessary to implement into the automated interconnection portal that processes thousands of applications a month.

PG&E also recommends a thorough review of a California Solar Initiative report conducted by EPRI titled "Screening Distribution Feeders: Alternatives to the 15% Rule." [15] This work is related to EPRI's work on hosting capacity and will help guide discussion of how ICA and these new techniques could get implemented within Rule 21.

Single Phase Line Sections

Expansion of the ICA to single phase line sections has been explored and is currently under development. It increases the processing and result set to what is already quite large so this must be properly discussed and considered. It may be appropriate and feasible for discussion in 2017, but there are factors that may not allow it to be implemented subsequent years. ICA analysis on single phase line sections depend on the accuracy of the phasing information in the circuit model, which may not be accurate in all cases. Proper phasing information will take longer than one year for full implementation into the models.

Data Access and Maps

IOUs will work with the ICAWG to discuss the data access issues including ways to make ICA information more user-friendly and easily accessible and understand market sensitive information.

The ICA maps provide a powerful tool for DER providers to site and size their projects. IOUs believe that thoughtful use of the maps and data behind the maps will enable widespread deployment of DER without impacting the distribution system. After stakeholders have a chance to test and experience the new ICA

[15] http://www.calsolarresearch.org/88-screening-distribution-feeders-alternatives-to-the-15-rule

maps, IOUs will work with ICAWG to identify possible improvements. Depending on the discussions, the actual implementation may take longer and become a long term refinement.

The preparation of online maps and downloadable data files in Demo A has shown that the data sizes are significant even for the two selected DPAs, which represent only a small portion of the entire service territory. While visual presentation of various scenarios can provide valuable information to assist in planning, the significant amount of information can also make the process cumbersome and confusing, which was also the reason why IOUs proposed to present the most practical and relevant scenario on the map and make other data downloadable for offline use, IOUs believe the marginal benefit of visually presenting more information may not be paid off by the effort required for both the developers and users.

9.d.ii Long Term Improvements (2+ years)

Other improvements have been identified, but may be suited for longer term discussions depending on the level of work required to implement.

Forecast Incorporation

It was recognized that there is a lack of inclusion of stochastic DER forecast after benchmarking with other development of hosting capacity efforts in the industry. Demo A utilized a simpler method of including these forecasts. More uncertainty and/or stochastic incorporation is needed given the uncertainty of exact locations of DER adoption.

At this point the ICA has had a major focus on interconnection and the impact of centralized DER. Interconnection is focused more on impact of DER one at a time. Going forward the methodology will have to incorporate and facilitate the understanding of the impact from distributed DER. A more distributed DER ICA result would be analyzed with similar granularity, but may provide results at a higher level such as feeder due to its nature of uncertainty at the node level. This will be very helpful for planning purposes in which exact location of DER within a circuit may not be predictable.

Load modifying resources such as demand response are generally controllable resources, which can have positive or negative impacts to the integration capacity. The uncertainties associated with these resources, arise from human behaviors, may present a different stochastic pattern. More complex methods to reflect the effect of potential load modifying resources on integration capacity may be helpful.

Validation and Consistency

Accurate ICA results are important for stakeholders in developing their project plans. An ICA validation plan that enables the results to be independently verified is necessary and beneficial. In order to drive more consistency, PG&E worked with the software vendors for implementation directly in the tools to lessen the amount of in house customization. For instance, PG&E utilized the CYMDIST "ICA Module" which is commercially available to all CYMDIST users. It should be noted that while this helps promote validation and consistency that it will be harder to make major adjustments if ICAWG or CPUC decide to do so. This should be a point of discussion during the meetings on long term items.

It will be important to ensure benchmarking with vendors and other institutions such as EPRI that are in full development of hosting capacity methods. This will be vital to creating a steady state solution that can be consistent across the industry that will benefit both the utilities performing the analysis and the developers and customers using the results.

Activity and Industry Alignment

Aligning ICA enhancement with other DER related industry initiatives and working group activities can potentially avoid redundant or conflicting efforts, improve the methodologies in an integrated manner, and maximize the value of the studies. For example, the interaction between ICA and LNBA can not only feed valuable information to each other but also provide meaningful information to the stakeholders in planning their projects. A location may be identified as having high DER locational benefits because the feeder is heavily loaded and has voltage issues, however, this location may not have a large ICA, due to the presence of regulator or switching devices, enough to defer a voltage support project in order to claim the locational benefits.

PG&E also recommends assessment of ICA currently within the rest of the industry outside of California to ensure a solution that is more consistent across state lines. This will be helpful for utility standardization and consistency for developers that also do business across state lines.

10 APPENDIX: ACR REQUIREMENTS COMPLIANCE MATRIX

10.a Compliance Matrix

Requirement	ACR Description	ACR	Project Report
Load forecasting and DER growth scenarios	IOUs shall use a transparent method for both load forecasting and DER growth in their ICA calculation methodology. DER growth scenarios will be approved in a separate Commission action. For purposes of both load forecasting and DER growth scenarios, Demonstration Project A shall be conducted using the following scenarios: · 2-year growth scenario as required in the Guidance and described above; and · Growth scenarios I and III as proposed in the DRP Applications. · Each scenario shall be conducted in two different DPAs that are selected to represent the range of physical and electrical conditions within the respective IOU distribution systems.	Section 1.1, p5	5.b
Baseline ICA Methodology Steps			
Establish distribution system level of granularity	Analysis shall be performed down to specific nodes within each line section of individual distribution feeders. Nodes shall be selected based on impedance factor, which is the measure of opposition that a circuit presents to electric current on application of voltage. Minimum and maximum (i.e. best and worst case) ranges of results shall be evaluated using lowest and highest impedance.	Section 1.3, p 6	4.b
Model and extract power system data	A Load Forecasting Analysis Tool (e.g. Load SEER) shall be used to develop load profiles at feeder, substation and system levels by aggregating representative hourly customer load and generation profiles.8 Load profiles shall be created for each DPA. The load profiles are comprised of 576 data points representing individual hours for the 24-hour period during a typical low-load day and a typical high-load day for each month (2 days * 24 hrs * 12 months = 576 points). A Power Flow Analysis Tool (e.g. CYMEDist for PG&E and SCE and Synergi Electric for SDG&E) shall be used to model conductors, line devices, loads and generation components that impact distribution circuit power quality and reliability. The Power Flow Analysis Tool shall be updated with the latest circuit configurations based on changes to the GIS asset map per the current practice of each utility.	Section 1.3, p 7	4.c
Evaluate power system criterion to determine DER capacity	The Load Forecast Tool and Power Flow Analysis Tool shall be used to evaluate power system criterion for the nodes and line sections that determine DER capacity limits on each distribution feeder. ICA results are dependent on the most limiting power system criteria. This could be any one of the factors listed in PG&E's Table 2-4 in their DRP Application under "Initial Analysis" and summarized below: (a). Thermal Criteria – determined based on amount of additional load and generation that can be placed on the	Section 1.3, p 7-9	4.d

	distribution feeder, without crossing the equipment ratings. (b). Power Quality / Voltage Criteria – voltage fluctuation calculated based on system voltage, impedances and DER power factor. Voltage fluctuation of up to 3% is part of the system design criteria for all three utilities. (c). Protection Criteria – determined based on required amount of fault current fed from the sub-transmission system due to DER operation. This is an area that the Working Group shall further develop. A potential starting point is the approach of PG&E as follows: Reduction of reach concept for generators was used with 10% evaluation as a flag for issues with the protection schemes. PG&E assumes that DER inverters contribute 120% rated current compared to 625% rated current from synchronous machines for a short circuiton the terminals. (d). Safety/Reliability Criteria – determined based on operational flexibility that accounts for reverse power flow issues when DER/DG is generating into abnormal circuit operating scenarios. Other limitations supporting the safe and reliable operation of the distribution system apply.		
Calculate ICA results and display on online map	The ICA calculations shall be performed using a layered abstraction approach where each criteria limit is calculated for each layer of the system independently and the most limiting values are used to establish the integration capacity limit. The ICA calculations shall be performed in a SQL11 server database or other platform as required for computation efficiency purposes. The resulting ICA data shall be made publicly available using the Renewable Auction Mechanism (RAM) Program Map. The ICA maps shall be available online and shall provide a user with access to the results of the ICA by clicking on a feeder displayed on the map. For the purposes of Demonstration Project A, the current utility map displays shall be used until further direction on a common approach is provided by the Commission.	Section 1.3, p 9	4.d.i
Specific Modifications to Include in Baseline Methodology			
Quantify the Capability of the Distribution System to Host DER	(a) Devices that contribute to reactive power on the circuit (e.g. capacitors, etc.) and their effect on the power flow analysis shall be included in the power flow model	Section 1.4, P 9-10 (and Section 1.1, p 1-2)	4.c
	(b). Power flow analysis shall be calculated across multiple feeders, whenever feasible for more accurate ICA values. All feeders that are electrically connected within a substation shall be included in this analysis.	Section 1.4, P 9-10	4.c
	(c). The ICA shall be modified to reflect DERs that reduce or modify forecast loads.	Section 1.4, P 9-10	4.c
	(d). Disclose any unique assumptions utilized to customize the power flow model of each IOU and all other calculation that could impact the ICA values.	Section 1.4, P 9-10	4

Common Methodology Across All Utilities	The "baseline" methodology with modifications described in this ruling will be used as a provisional common ICA methodology used by all IOUs in the Demonstration A Projects. At this time, SCE and SDG&E are required to adopt the modified baseline methodology described in this ruling, which is derived from PG&E's basic methodology. SCE and SDG&E's power flow analysis and load forecast tool methodologies should be adapted, as required, using PG&Es methodology as the basis.	Section 1.4, p 10 (and Section 1.1, p 2)	4
Different Types of DERs	(a) The methodology shall evaluate the capacity of the system to host DERs using a set of 'typical' DER operational profiles. PG&E has developed a set of profiles that provide a starting point. These profiles are: Uniform Generation, PV, PV with Tracker, EV – Residential (EV Rate), EV – Workplace, Uniform load, PV with Storage, Storage – Peak Shaving, EV – Residential (TOU rate)	Section 1.4, p 11 (and Section 1.1, p 2)	8.b
	(b). ICA shall quantify hosting capacity for portfolios of resource types using PG&E's approach with representative portfolios of i. solar, ii. solar and stationary storage, iii. solar, stationary storage, and load control and iv. solar, stationary storage, load control, and EVs.	Section 1.4, p 11	8.b
	(c). Utilities shall propose a method for evaluating DER portfolio operational profiles that minimize computation time while accomplishing the goal of evaluating the hosting capacity for various DER portfolios system-wide.	Section 1.4, p 11-12	8.b
	(d) The ICA Working Group shall identify additional DER portfolio combinations	Section 1.4, p 12	8.b
Granularity of ICA in Distribution System	Locational granularity of ICA is defined as line section or node level on the primary distribution system, as specified in the PG&E methodology	Section 1.4, p 12 (and Section 1.1, p 2)	4.b
Thermal Ratings, Protection Limits, Power Quality (including Voltage), and Safety Standards	(a) Include all the different types of defined power system criteria and subcriteria in the analysis. i. In Table 2-4 in its DRP application, PG&E has indicated a set of power system criteria to be used in a "Potential Future Analysis." All items on this list should be incorporated to the extent feasible initially, with the objective of complete inclusion as the capabilities become available.	Section 1.4, p 12 (and Section 1.1, p 2)	4.d.ii, 4.d.iii, 4.d.iv, 4.d.v
	(b) Protection Limits used in ICA – The IOUs shall agree upon on a common approach to representing protection limits in the ICA.	Section 1.4, p 12	4.d.iv
	(c) Utilities shall provide documentation to describe the ICA limit criteria and threshold values and how they are applied in the Demonstration A Projects, in an intermediate status report, due Q3 2016.	Section 1.4, p 13	4.d
	(d). Utilities shall provide documentation to identify and explain the industry, state, and federal standards embedded within the ICA limitation criteria and threshold values, and include this in Final Report due early Q4 2016.	Section 1.4, p 13	4.d
	(e). Included with ICA results for each feeder provide i. Feeder-level	Section	7.b

	loading and voltage data, ii. Customer type breakdown, iii. Existing DER capacity (to the extent not already available).	1.4, p 13	
	(f). Identify feeders where sharing the information in paragraph "e" violates any applicable data sharing limitations.	Section 1.4, p 13	7.b[16]
	(g). ICA results should include detailed information on the type, frequency, timing (diurnal and seasonal) and duration of the thermal, voltage, or system protection constraints that limit hosting capacity on each feeder segment. The information shall be in a downloadable format and with sufficient detail to allow customers and DER providers to design portfolios of DER to overcome the constraints. This information may include relevant load and voltage profiles, reactive power requirements, or specific information related to potential system protection concerns.	Section 1.4, p 13-14	7.b.ii[17]
Publish the Results via Online Maps	(a) All information made available in this phase of ICA development shall be made available via the existing ICA maps in a downloadable format. The feeder map data shall also be available in a standard shapefile format, such as ESRI ArcMap Geographic Information System (GIS) data files.21 The maps and associated materials and download formats shall be consistent across all utilities and should be clearly explained through the inclusion of "keys" to the maps and associated materials. Explanations and the meanings of the information displayed shall be provided, including any relevant notes explaining limitations or caveats. Any new data types developed in the ICA Working Group shall be published in a form to be determined in the data access portion of the proceeding.	Section 1.4, p 14 (and Section 1.1, p 2)	7
	(b) Existing RAM map information and ICA results shall be displayed on the same map. RAM information shall be the default information displayed on that map with ICA data available if the user specifies it.	Section 1.4, p 14	7
Time Series or Dynamic Models	ICA shall utilize a dynamic or time series analysis method as specified in the Guidance. This analysis shall be consistent among the three IOUs. The IOUs currently use different power flow analysis tools that may implement a time series analysis differently. The methodology used by the three IOUs should therefore be based on capabilities that are common among the tools that support a consistent result. IOUs shall consult with the ICA Working Group to ensure that the power flow analysis tools use an equivalent approach to dynamic or time series analysis.	Section 1.4, p 14-15 (and Section 1.1, p 2)	4
Avoid Heuristic approaches, where possible	There are no new modifications based on this Guidance requirement	Section 1.4, p 15 (and	n/a

[16] PG&E is still finalizing the maps and data files and will update the CPUC and ICAWG upon completion.
[17] Same as previous footnote

		Section 1.1, p 2)	
General Requirements			
Power Flow Scenarios	The Guidance Ruling required the IOUs to model two scenarios in their Demonstration A projects: (a) The DER capacity does not cause power to flow beyond the substation busbar. (b) The DERs technical maximum capacity is considered irrespective of power flow toward the transmission system.	Section 2, p 15 (and Section 1.1, p 4)	5.b
Project Schedule	Demonstration A project schedules proposed in IOU Applications are modified and shall commence immediately with the issuance of this Ruling.	Section 2, p 16	n/a
Project Locations	Demonstration A project locations proposed in the Applications are modified and shall include two DPAs that cover as broad a range as possible of electrical characteristics encountered in the respective IOU systems (e.g., one rural DPA and one urban DPA). The IOUs shall clarify if their originally proposed Demonstration A project locations satisfies one of the two required DPAs and what their other proposed DPA(s) are. The IOUs shall also justify in their detailed plans the basis for choosing each DPA for the Demonstration Projects.	Section 2, p 16 (and Section 1.1, p 3)	3
Project Detailed Implementation Plan	The IOUs shall submit detailed implementation plans for project execution, including metrics, schedule and reporting interval. To the extent practicable, the IOUs shall consult with the ICA Working Group on the development of the plan. The plan shall be submitted to the CPUC within as a status update within 45 days of this ruling and served to the R.14-08-013 service list. The ICA Demo A Plan shall include (a) Documentation of specific and unique project learning objectives for each of the Demonstration A projects, including how the results of the projects are used to inform ICA development and improvement; (b). A detailed description of the revised ICA methodology that conforms to the guidance in Section 1.3 and Section 1.4 above, including a process flow chart. (c). A description of the load forecasting or load characterization methodology or tool used to prepare the ICA; (d). Schedule/Gantt chart of the ICA development process for each utility, showing: i. Any external (vendor or contract) work required to support it. ii. Additional project details and milestones including, deliverables, issues to be tested, and tool configurations to be tested; (e). Any additional resources required to implement Project A not described in the Applications; (f). A plan for monitoring and reporting intermediate results and a schedule for reporting out. At a minimum, the Working Group shall report out at least two times over the course of the Demonstration A project: 1) an intermediate report; and 2) the final report. (g). Electronic files shall be made available to the CPUC Energy Division and ORA to view and validate inputs, models, limit criteria, and results. Subject to appropriate confidentiality rules, other parties may	Section 2, p16-18	n/a

	also request copies of these files; (h). Any additional information necessary to determine the probability of accurate results and the need for further qualification testing for the wider use of the ICA methodology and to provide the ultimate evaluation of ex-post accuracy. (i). ORA's proposed twelve (12) criteria or metrics of success to evaluate IOU ICA tools, methodologies and results are adopted and should be used as guiding principles for evaluating ICA.		

11 APPENDIX: ICA CRITERIA TABLES

11.a ICA Criteria Definition

Table 2: Criteria Definitions

Thermal	**Exceeding thermal limits of specified equipment**
– Substation Transformer	--
– Circuit Breaker	--
– Primary Conductor	--
– Main Line Devices	--
– Tap Line Devices	--
Voltage / Power Quality	**Creating power quality conditions outside acceptable ranges**
– Transient Voltage	Short time period relative voltage variation outside acceptable limits
– Steady State Voltage	Exceeding voltage outside ANSI voltage range
– Voltage Regulator Impact	Creating conditions for regulator to improperly manage voltage
– Substation Load Tap Changer Impact	Creating conditions for LTC to improperly manage voltage
Protection	**Creating issues that impact protection schemes**
– Protective Relay Reduction of Reach	Reducing bulk system fault contribution to protection devices
Safety/Reliability	**Creating conditions that diminish operating reliability and safety**
– Transmission Penetration	Limiting reverse flow into the transmission system
– Operational Flexibility	Reducing possible reverse flow in abnormal switching conditions

11.b ICA Criteria

Table 3: Criteria Analyzed in Demo A

	Streamlined	Iterative
Thermal		
– Substation Transformer	✓	1
– Circuit Breaker	✓	✓
– Primary Conductor	✓	✓
– Main Line Devices	✓	✓
– Tap Line Devices	✓	✓
– Service Transformer		
– Secondary Conductor		
– Transmission Line		
Voltage / Power Quality		
– Transient Voltage	✓	✓
– Steady State Voltage	✓	✓
– Voltage Regulator Impact	✓	2
– Substation Load Tap Changer Impact	3	4
– Harmonic Resonance / Distortion		
– Transmission Voltage Impact		
Protection		
– Protective Relay Reduction of Reach	5	✓
– Fuse Coordination		
– Sympathetic Tripping		
– Transmission Protection		
Safety/Reliability		
– Islanding	6	7
– Transmission Penetration	✓	✓
– Operational Flexibility	✓	✓
– Transmission System Frequency		
– Transmission System Recovery		

Legend	
Included	✓
See Notes	#
Not in Demo	

Scope	[redacted]

*Notes are on the next page.

Notes for Table 3

1. Substation transformer is not modeled in CYME and could not be directly evaluated in iterative, but was included using the layered abstraction with similar approach in streamlined.
2. The ICA module by CYME locked all voltage devices in CYME and thus could not evaluate its operation. Similar reverse flow evaluation as streamlined could be performed but could not be separated out of reverse flow evaluation for different device types. Thus inclusion of the regulator reverse flow was in Operational Flexibility.
3. Similar evaluation would be the same as the "transmission penetration" category. Thus it was not considered independently at this time within Demo A.
4. The basic effect of the LTC is simulated, but currently the PG&E models do not support full LTC operations directly due to the complexity of complete substation modeling.
5. This category was included in analysis, but used Short Circuit Contribution Ratio in its current form. Research could be done to align more directly to the specific criteria similar to what EPRI's methodology has done.
6. Due to limited applicability of Islanding screens for new standards, this screen was not used in Demo A. Further refinement may explore inclusion as appropriate.
7. Since the islanding screens are simply general screening and not simulations, iterative would not be necessary. Also, the more direct transient evaluation/simulation of islanding is not feasible for general interconnection evaluation which is why simpler screening methods are utilized.

11.c Assumptions and Thresholds

Table 4: Threshold Values

	Streamlined	Iterative
Thermal	Device Thermal Rating	Device Thermal Rating
– Substation Transformer	"	"
– Circuit Breaker	"	"
– Primary Conductor	"	"
– Main Line Devices	"	"
– Tap Line Devices	"	"
Voltage / Power Quality		
– Transient Voltage	3%	3%
– Steady State Voltage	95% and 105%*	95% and 105%*
– Voltage Regulator Impact	Reverse Flow	Reverse Flow
– Substation Load Tap Changer Impact	Reverse Flow	Reverse Flow
Protection		
– Protective Relay Reduction of Reach	10% **	Phase: 130%*** Ground: 400%***
Safety/Reliability		
– Transmission Penetration	Reverse Flow	Reverse Flow
– Operational Flexibility	Reverse Flow	Reverse Flow

* These thresholds represent the ANSI and Rule 2 limits. These represent the threshold at the customer meter and the current ICA modeling stops at the primary voltage side of the service transformer. It is recommended to revisit these thresholds to see if tighter bands are necessary since secondary transformers are not evaluated yet.

**10% relates to Short-Circuit Contribution Ratio

*** 130% and 400% refer to the amount of fault current a protective device must see in relation to its minimum trip settings. It is intended to review these thresholds further with PG&E's protection department for further refinement.

12 APPENDIX: ICA ADDITIONAL RESULTS

The following two tables help summarize the ICA results by each feeder. Table 5 shows the results for generation and Table 6 for load. Each row describes three numbers for the nodes with the identified limiting criteria for each feeder. "Max IC" is the maximum IC for all nodes on that feeder with the limiting criteria identified. "Min IC" is similar, but the minimum IC. "% Share of FDR Nodes" quantifies how much of the IC node results for that feeder are limited by the identified limiting criteria.

Table 5: Feeder Summary of Min/Max Gen IC by Limiting Criteria

Substation	Network	Limiting Criteria	Max IC	Min IC	% Share of Feeder Nodes
ANITA	102841101	Thermal	2,333	1,977	0.4%
		PQ	5,174	0	51.9%
		Safety	5,175	0	47.7%
	102841102	Thermal	2,524	1,977	4.5%
		PQ	4,253	0	63.5%
		Protection	4,417	3,083	0.5%
		Safety	4,451	0	31.5%
BUTTE	103081103	Thermal	10,653	1,977	16.3%
		PQ	10,689	0	58.6%
		Protection	11,917	3,667	0.6%
		Safety	11,897	0	24.4%
	103081104	Thermal	6,749	1,977	8.6%
		PQ	11,024	0	57.8%
		Protection	11,917	2,500	2.1%
		Safety	11,897	0	31.6%
	103081105	Thermal	9,918	1,977	14.2%
		PQ	14,966	0	27.9%
		Protection	15,417	7,250	2.5%
		Safety	15,415	0	55.4%
	103081106	Thermal	12,718	1,977	51.5%
		PQ	15,160	0	10.9%
		Protection	15,417	7,917	2.7%
		Safety	15,415	0	35.0%

Substation	Network	Limiting Criteria	Max IC	Min IC	% Share of Feeder Nodes
	103081107	Thermal	11,441	1,977	8.0%
		PQ	14,742	0	72.6%
		Protection	15,333	3,333	1.9%
		Safety	15,326	0	17.5%
CHICO A	102051101	Thermal	7,925	1,977	12.2%
		PQ	10,746	0	18.1%
		Protection	11,083	7,583	4.3%
		Safety	11,078	0	65.5%
	102051102	Thermal	4,646	685	19.7%
		PQ	9,608	0	26.9%
		Protection	11,083	5,000	2.0%
		Safety	11,078	0	51.3%
	102051103	Thermal	4,409	1,977	39.7%
		PQ	10,564	0	37.6%
		Protection	11,083	5,250	9.7%
		Safety	11,078	0	13.0%
CHICO B	102491101	Thermal	10,249	1,977	41.4%
		PQ	10,046	0	29.7%
		Protection	10,417	6,583	3.8%
		Safety	10,409	0	25.0%
	102491102	Thermal	7,844	7,844	4.0%
		PQ	10,076	1,670	42.6%
		Protection	10,417	10,000	2.5%
		Safety	10,409	5,383	50.9%
	102491103	Thermal	10,180	1,977	24.2%
		PQ	10,140	0	30.6%
		Protection	10,333	3,667	2.9%
		Safety	10,329	0	42.3%
	102491105	Thermal	8,579	1,977	30.6%
		PQ	9,036	0	15.7%
		Protection	10,333	4,750	2.8%
		Safety	10,315	0	51.0%
	102491106	Thermal	8,416	2,017	45.0%
		PQ	9,947	0	30.4%
		Protection	10,500	7,833	1.9%
		Safety	10,500	0	22.6%
CHOWCHILLA	254101101	Thermal	8,262	1,977	20.2%
		PQ	16,089	0	51.6%

Substation	Network	Limiting Criteria	Max IC	Min IC	% Share of Feeder Nodes
		Protection	17,167	3,583	2.7%
		Safety	17,160	0	25.4%
	254101102	Thermal	11,499	2,185	32.9%
		PQ	16,123	0	42.0%
		Protection	17,250	7,333	1.0%
		Safety	17,207	0	24.2%
	254101103	PQ	0	0	1.4%
		Safety	21,153	0	98.6%
	254101104	Thermal	6,819	1,977	7.2%
		PQ	16,132	0	78.6%
		Protection	17,167	2,167	3.5%
		Safety	17,160	0	10.7%
	254101105	Thermal	5,589	1,977	8.4%
		PQ	6,855	0	36.3%
		Safety	6,986	0	55.3%
	254101106	Thermal	5,574	1,977	8.4%
		PQ	5,236	273	29.6%
		Protection	5,750	4,750	0.5%
		Safety	6,335	0	61.5%
DAIRYLAND	252421102	Thermal	9,427	1,977	4.9%
		PQ	12,013	0	84.4%
		Protection	16,000	3,750	2.8%
		Safety	15,982	0	7.9%
	252421103	Thermal	7,370	1,977	2.5%
		PQ	4,869	0	93.8%
		Safety	12,078	0	3.7%
	252421105	Thermal	2,799	1,977	3.8%
		PQ	4,349	0	66.2%
		Protection	7,917	1,000	11.7%
		Safety	7,942	0	18.3%
	252421109	Safety	10,511	0	100.0%
EL NIDO	252451101	Thermal	3,617	1,977	4.7%
		PQ	6,496	272	74.2%
		Protection	5,083	4,083	0.0%
		Safety	6,728	0	21.2%
	252451102	Thermal	3,121	1,977	9.6%
		PQ	10,409	0	60.7%
		Protection	11,417	3,083	6.3%

Substation	Network	Limiting Criteria	Max IC	Min IC	% Share of Feeder Nodes
		Safety	11,410	0	23.4%
	252451103	Thermal	4,448	1,977	13.7%
		PQ	10,547	178	62.1%
		Protection	11,000	4,083	1.5%
		Safety	10,997	0	22.7%
	252451104	Protection	0	0	34.0%
		Safety	0	0	66.0%
ESQUON	102171101	Protection	0	0	49.5%
		Safety	0	0	50.5%
	102171102	Thermal	2,390	1,977	6.7%
		PQ	5,732	0	61.1%
		Protection	5,833	2,667	2.4%
		Safety	5,821	0	29.8%
	102171103	Thermal	3,410	1,977	9.0%
		PQ	5,733	0	77.4%
		Protection	5,833	2,750	1.9%
		Safety	5,821	0	11.7%
LE GRAND	255361104	Safety	15,833	0	100.0%
	255361106	Safety	15,833	0	100.0%
	255361110	Safety	25,982	0	100.0%
NORD	103071103	Thermal	6,819	1,977	3.2%
		PQ	9,214	0	26.0%
		Protection	10,333	4,333	2.8%
		Safety	10,308	0	68.0%
	103071104	Thermal	4,151	1,977	14.7%
		PQ	9,506	0	40.0%
		Protection	10,500	3,667	3.7%
		Safety	10,499	0	41.6%
	103071105	Thermal	5,999	1,983	50.9%
		PQ	9,356	0	24.1%
		Protection	9,833	5,333	5.7%
		Safety	9,811	-666	19.2%
	103071106	Thermal	3,840	1,977	55.0%
		PQ	9,291	886	6.9%
		Protection	10,250	4,583	15.5%
		Safety	10,235	0	22.6%
NOTRE DAME	102041101	Thermal	16,082	2,185	42.5%
		PQ	14,949	0	40.7%

Substation	Network	Limiting Criteria	Max IC	Min IC	% Share of Feeder Nodes
		Protection	16,083	7,500	7.8%
		Safety	15,180	0	9.0%
	102041102	Thermal	14,365	1,989	52.3%
		PQ	0	0	3.6%
		Protection	16,083	11,333	1.3%
		Safety	16,066	0	42.7%
	102041103	Thermal	16,076	2,851	70.5%
		PQ	15,020	658	24.3%
		Protection	16,083	13,917	0.5%
		Safety	15,833	0	4.8%
	102041104	Thermal	14,726	2,185	32.5%
		PQ	2,849	0	25.1%
		Protection	15,917	6,750	7.2%
		Safety	15,913	0	35.1%
NULL	102841105	Thermal	3,122	1,977	14.7%
		PQ	3,663	0	33.7%
		Protection	8,000	3,417	5.1%
		Safety	8,122	0	46.5%
	102841106	Thermal	3,128	1,977	7.5%
		PQ	4,912	0	63.7%
		Protection	8,083	4,333	0.9%
		Safety	8,090	0	28.0%
SYCAMORE CREEK	102971101	Thermal	16,010	1,977	44.0%
		PQ	14,667	0	40.6%
		Protection	15,250	5,417	4.2%
		Safety	16,019	0	11.2%
	102971102	Thermal	16,998	1,977	30.9%
		PQ	16,481	0	27.4%
		Protection	17,000	5,000	9.4%
		Safety	15,833	0	32.2%
	102971103	Thermal	15,441	2,185	46.4%
		PQ	13,847	0	35.3%
		Protection	15,083	7,833	6.7%
		Safety	14,417	0	11.6%
	102971104	Thermal	16,998	1,977	28.2%
		PQ	12,609	0	38.6%
		Protection	17,000	4,667	22.3%

Substation	Network	Limiting Criteria	Max IC	Min IC	% Share of Feeder Nodes
		Safety	17,000	0	11.0%
	102971105	Thermal	4,982	1,977	47.4%
		PQ	11,160	0	1.4%
		Protection	12,167	3,750	11.8%
		Safety	12,146	0	39.4%
	102971107	Thermal	8,379	1,977	61.0%
		PQ	0	0	1.9%
		Protection	10,500	8,917	0.4%
		Safety	10,662	0	36.7%
	102971109	Thermal	14,726	2,006	27.2%
		PQ	14,908	0	32.0%
		Protection	15,583	4,417	5.7%
		Safety	15,554	0	35.2%
	102971110	Thermal	5,555	1,977	69.2%
		PQ	2,257	0	3.2%
		Protection	15,083	5,667	18.5%
		Safety	15,165	0	9.0%
	102971111	Thermal	14,743	1,982	54.2%
		PQ	2,546	0	2.2%
		Protection	13,333	4,000	11.6%
		Safety	14,636	0	32.0%

Table 6: Feeder Summary of Min/Max Load IC by Limiting Criteria

Substation	Network	Limiting Criteria	Max IC	Min IC	% Share of Feeder Nodes
ANITA	102841101	Thermal	3,396	94	6.5%
		PQ	5,175	0	93.5%
	102841102	Thermal	2,983	1,105	13.6%
		PQ	4,451	0	86.4%
BUTTE	103081103	Thermal	11,917	595	27.4%
		PQ	11,917	0	72.6%
	103081104	Thermal	11,917	243	14.9%
		PQ	11,917	0	85.1%
	103081105	Thermal	15,417	204	39.3%
		PQ	15,417	0	60.7%
	103081106	Thermal	15,417	198	67.1%
		PQ	15,417	0	32.9%
	103081107	Thermal	15,333	0	14.6%
		PQ	15,333	0	85.4%
CHICO A	102051101	Thermal	11,083	213	50.3%
		PQ	11,083	0	49.7%
	102051102	Thermal	11,083	685	44.7%
		PQ	11,083	0	55.3%
	102051103	Thermal	11,083	1,977	51.7%
		PQ	11,083	0	48.3%
CHICO B	102491101	Thermal	10,417	364	57.7%
		PQ	10,417	0	42.3%
	102491102	Thermal	10,417	5,383	55.0%
		PQ	10,417	1,670	45.0%
	102491103	Thermal	10,333	953	52.7%
		PQ	10,333	0	47.3%
	102491105	Thermal	9,553	239	60.6%
		PQ	10,333	0	39.4%
	102491106	Thermal	10,500	2,017	64.2%
		PQ	10,500	0	35.8%
CHOWCHILLA	254101101	Thermal	17,167	377	31.2%
		PQ	17,167	0	68.8%
	254101102	Thermal	17,250	1,486	50.4%
		PQ	17,250	0	49.6%
	254101103	Thermal	21,153	463	48.0%
		PQ	21,072	0	52.0%
	254101104	Thermal	17,167	1,486	8.9%

		PQ	17,167	0	91.1%
	254101105	Thermal	6,335	288	42.3%
		PQ	6,986	0	57.7%
	254101106	Thermal	6,335	288	49.9%
		PQ	6,335	0	50.1%
DAIRYLAND	252421102	Thermal	16,000	25	9.0%
		PQ	12,340	0	91.0%
	252421103	Thermal	12,078	1,425	4.0%
		PQ	4,869	0	96.0%
	252421105	Thermal	7,942	1,425	9.2%
		PQ	7,942	0	90.8%
	252421109	Thermal	10,511	0	29.0%
		PQ	10,196	0	71.0%
EL NIDO	252451101	Thermal	6,120	896	13.9%
		PQ	6,728	0	86.1%
	252451102	Thermal	11,417	1,097	14.1%
		PQ	11,417	0	85.9%
	252451103	Thermal	11,000	896	24.4%
		PQ	11,000	0	75.6%
	252451104	Thermal	0	0	33.0%
		PQ	0	0	67.0%
ESQUON	102171101	Thermal	0	0	66.1%
		PQ	0	0	33.9%
	102171102	Thermal	2,390	1,977	6.7%
		PQ	5,833	0	93.3%
	102171103	Thermal	4,130	1,977	9.2%
		PQ	5,833	0	90.8%
LE GRAND	255361104	Thermal	15,833	1,977	6.4%
		PQ	15,833	0	93.6%
	255361106	Thermal	15,833	1,977	7.8%
		PQ	8,167	0	92.2%
	255361110	Thermal	25,982	0	62.6%
		PQ	25,641	0	37.4%
NORD	103071103	Thermal	9,656	411	31.2%
		PQ	10,333	0	68.8%
	103071104	Thermal	10,500	154	25.5%
		PQ	10,500	0	74.5%
	103071105	Thermal	9,334	1,983	60.6%
		PQ	9,833	-666	39.4%
	103071106	Thermal	10,193	189	75.0%

		PQ	10,250	0	25.0%
NOTRE DAME	102041101	Thermal	16,083	2,185	50.1%
		PQ	15,917	0	49.9%
	102041102	Thermal	16,083	377	89.3%
		PQ	1,161	0	10.7%
	102041103	Thermal	16,083	2,851	73.1%
		PQ	15,583	0	26.9%
	102041104	Thermal	15,917	1,897	41.3%
		PQ	6,917	0	58.7%
NULL	102841105	Thermal	7,917	580	20.9%
		PQ	8,122	0	79.1%
	102841106	Thermal	6,917	211	9.0%
		PQ	8,090	0	91.0%
SYCAMORE CREEK	102971101	Thermal	16,019	1,977	48.2%
		PQ	15,533	0	51.8%
	102971102	Thermal	17,000	345	52.9%
		PQ	17,000	0	47.1%
	102971103	Thermal	15,441	2,185	58.8%
		PQ	14,417	0	41.2%
	102971104	Thermal	17,000	1,977	44.0%
		PQ	15,083	0	56.0%
	102971105	Thermal	12,167	1,509	74.9%
		PQ	12,167	0	25.1%
	102971107	Thermal	10,662	498	91.6%
		PQ	815	0	8.4%
	102971109	Thermal	15,583	209	43.8%
		PQ	15,583	0	56.2%
	102971110	Thermal	15,165	102	90.0%
		PQ	7,833	0	10.0%
	102971111	Thermal	14,743	292	80.2%
		PQ	9,667	0	19.8%

APPENDIX B

PACIFIC GAS AND ELECTRIC COMPANY

LOCATIONAL NET BENEFIT ANALYSIS

DEMONSTRATION PROJECT B – LOCATIONAL NET BENEFIT ANALYSIS

FINAL REPORT

December 2016

Table of Contents

1 Executive Summary

This Distribution Resources Plan (DRP) demonstration of Locational Net Benefit Analysis (LNBA) is a first step toward a robust, highly-granular and need-based approach to evaluating the location-specific benefit of Distributed Energy Resources (DERs). This level of analysis is particularly essential for benefits related to Transmission and Distribution (T&D) functions, where there is a high level of variability in needs from one circuit to the next.

In this DRP LNBA Demonstration Project (Demo B), Pacific Gas and Electric Company (PG&E) implemented a number of new planning analyses to specify and quantify potential T&D benefits of DERs, which are the most locational of the LNBA components, in two areas of its territory: Chico and Chowchilla Distribution Planning Areas. Other LNBA components, such as avoided energy benefits, are included at a system-wide level.

In consultation with a public LNBA Working Group, PG&E developed, jointly with Southern California Edison (SCE), San Diego Gas and Electric Company (SDG&E) and Energy and Environmental Economics (E3) as consultant, a public LNBA Tool for Demo B. This report details the functions of this tool and how PG&E applied it to Chico and Chowchilla in Demo B.

Potential DER T&D benefits, which are derived from deferring capital investments that would otherwise have been needed, are evaluated throughout these two areas and nine T&D upgrade project deferral opportunities are evaluated in detail. The results of that analysis are presented in Chapter 5 and also in a public heat map which includes downloadable feeder-level data that was used in the analysis.

Results for nine deferral opportunities are distributed across three tranches of value from less than 100 $/kW to over 500 $/kW. These results were not significantly altered under a Very High DER Growth sensitivity.

PG&E collaborated closely with its utility partners on other sections of this report that describe the LNBA tools and methods used in Demo B along with the heat map specifications.

Demo B is a preliminary attempt to execute the LNBA at a small scale, and many opportunities to refine and expand exist – much work remains to implement or use this analysis at a wide scale to realize the vision of the DRP. Areas for refinement include DER Growth Scenario development, capturing uncertainty, and evaluation of transmission investment deferral opportunities.

PG&E expects that portions of the analyses developed in Demo B will be incorporated into an annual cycle linked closely to the annual distribution planning process upon which the LNBA heavily relies. Given the likelihood that this type of analysis may be used to inform market mechanisms for deploying DERs in optimal locations, PG&E has not included any market sensitive or confidential information in this report or the analysis results.

Ultimately, this type of analysis will lead to more precise, specific and granular data to inform DER-related discussions, including those related to development of market mechanisms which seek to deploy DERs in optimal locations and achieve the grid benefits and utility customer savings that are central to the DRP.

2 Objectives and Background

The genesis of the locational net benefit analysis is Assembly Bill (AB) 327 of 2014, which added section 769(b) to the California Public Utilities Code, requiring each California Investor Owned Utility (IOU) to submit a distribution resources plan proposal "to identify optimal locations for the deployment of distributed resources…" using an evaluation of "locational benefits and costs of distributed resources located on the distribution system" based on savings distributed energy resources[1] provide to the electric grid or costs to utility customers.

Today's methods for evaluating DERs do not consider differences in benefits at one location compared to another, or if they do it is done at a less granular level or in a context that influences actual DER deployment.

The DRP envisions a future where DERs are deployed at optimal locations, times and quantities so that their benefits to the grid are maximized and utility customer costs are reduced. AB 327 recognized that achieving this vision requires advancing the analytical methods, tools and mechanisms by which DERs are deployed. This project, DRP Demonstration Project B (Demo B), advances one crucial set of those analytical methods: evaluation of DERs' benefits at specific locations.

The intent of Demo B is to develop and demonstrate methodologies to evaluate DERs' benefits – in particular, their benefits to the transmission and distribution (T&D) system – at a feeder-level and even higher levels of granularity. Ultimately, this will lead to more precise, specific and granular data to inform DER-related discussions, including related to development of market mechanisms which achieve the grid benefits and utility customer savings that are central to the DRP.

Demo B provides an initial demonstration of a number of new planning analyses. It is PG&E's expectation that these methods will continue to evolve as more experience is gained. The results of Demo B are expected to inform a Commission Decision in 2017 that will refine and expand the scope of this work. PG&E ultimately expects an LNBA tool that will provide useful information to DER providers and others seeking to deploy DERs in optimal locations.

PG&E also expects that portions of the analyses developed in Demo B will ultimately be incorporated into an annual cycle linked closely to the annual distribution planning processes upon which the LNBA heavily relies. The process of identifying conventional distribution projects as candidates for DER deferral, for example, is central to the Deferral Framework to be developed in Sub-track 3 of Track 3 of the DRP proceeding.

PG&E looks forward to continued engagement with the Commission and Stakeholders to refine these tools and expand their usefulness.

2.1 California Public Utilities Commission Guidance

On August 14, 2014, the California's Public Utilities Commission (Commission or CPUC) issued Rulemaking R. 14-08-013 which established guidelines, rules, and procedures to direct California investor-owned electric utilities to develop their DRPs. In a February 6, 2015 Assigned Commissioner

[1] Per AB 327, DERs includes distribution-connected energy efficiency, energy storage, distributed generation, demand response, and electric vehicles.

Ruling (ACR), the Commission released further guidance[2] for the IOUs, including requirements for an "optimal location benefit analysis" and demonstration projects, including this one.[3]

Following the IOUs' July 1, 2015 DRP filings and subsequent workshops on LNBA, an ACR dated May 2, 2016 (the May 2, ACR) provided additional guidance to the IOUs on further development of the LNBA in Demo B.[4]

The May 2, ACR approved an LNBA methodology framework for Demo B, instructed the IOUs to apply the LNBA methodology to a Distribution Planning Area (DPA), and directed the IOUs to submit a final report and results by the end of 2016.[5] [6]

2.1.1 May 2, ACR Definition of LNBA for Demo B

LNBA is essentially a combination of various benefit components evaluated at a location. The table below from the May 2, ACR lists the components of the LNBA as defined for Demo B, and, for each, indicates a basic or "primary" LNBA methodology as well as a more complex "secondary" option.[7]

[2] "Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning," February 6, 2015.
Available at: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M146/K374/146374514.PDF
[3] "Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning," February 6, 2015, Attachment A, pg. 4-6.
[4] "Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B," May 2, 2016.
Available at: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M161/K474/161474143.PDF
[5] Ibid, at pp. 25-34.
[6] Ibid, at pp. A26-A38.
[7] ibid, at pp. A26-A27.

Table 1: Demo B LNBA Components

Table 2 Approved LNBA Methodology Requirements Matrix for Demonstration Project B.

Components of avoided costs	Proposed LNBA in IOU Filings	Primary Analysis	Secondary Analysis
from DERAC	*from IOU applications*	*Required*	*Optional additional*
Avoided T&D	**Sub-Transmission / Substation / Feeder**	**As proposed but with modifications (1)**	**As proposed but with modifications (1)**
	Distribution Voltage / Power Quality	**As proposed but with modifications (1)**	**As proposed but with modifications (1)**
	Distribution Reliability / Resiliency	**As proposed but with modifications (1)**	**As proposed but with modifications (1)**
	Transmission	**As specified herein (2)**	**As specified herein (2)**
Avoided Generation Capacity	System and Local RA	Use DERAC values	Use DERAC values with location-specific line losses (3)
	Flexible RA	Use DERAC values with flexibility factor (4)	Use DERAC values with flexibility factor (4)
Avoided Energy	Use LMP prices to determine	Use DERAC values	As proposed but with modifications regarding use of LMP prices (5) and location-specific losses (3)
Avoided GHG	incorporated into avoided energy	Use DERAC values	As proposed
Avoided RPS	similar to DERAC	Use DERAC values	As proposed
Avoided Ancillary Services	similar to DERAC	Use DERAC values	As proposed
additional to the DERAC	Renewable Integration Costs	values or descriptions of these benefits (6)	values or descriptions of these benefits (6)
	Societal avoided costs	values or descriptions of these benefits (6)	values or descriptions of these benefits (6)
	Public safety costs	values or descriptions of these benefits (6)	values or descriptions of these benefits (6)

The T&D avoided costs, highlighted in the ACR table above, are the central focus of Demo B, since they are the LNBA component most sensitive to location. These benefits are based on DERs' ability to defer a specific transmission or distribution capital investment, thereby reducing the IOU revenue requirement and hence utility customer cost. The IOUs were directed to consider four categories of T&D capital projects for deferral in Demo B as enumerated in the table above.

Most non-T&D components of the LNBA in Demo B are borrowed from the existing DER Avoided Cost calculator or DERAC [8] or are expansions upon the DERAC in the case of flexible and local RA and

[8] https://ethree.com/public_projects/cpuc4.php

renewable integration cost. These non-T&D components are sometimes collectively referred to in this report as system-level avoided costs. It is expected that future LNBA refinements will explore more locational approaches for these components as well.

Definition of Net in Demo B

In a typical net benefit analysis, total net benefits represent the net present value of benefits minus the net present value of costs. However, Table 2 of the ACR[9] does not include DER costs as a LNBA component in Demo B. The meaning of net in LNBA for Demo B instead can refer to the fact that each component can be either positive or negative, the combination of which is a net result.[10]

2.1.2 May 2, ACR Requirements and Deliverables for Demo B

To summarize the May 2, ACR requirements for Demo B, IOUs were directed to:

1. Select one or more DPAs that include "one near-term and one longer-term distribution infrastructure project for possible deferral"[11] and "at least one voltage support/power quality- or reliability/resiliency-related deferral opportunity in addition to one or more capacity-related opportunities;"[12]
2. Identify, for every location in the selected DPA(s), "the full range of electric services that result in avoided costs" including "any and all electrical services associated with distribution grid upgrades identified in (i) the utility distribution planning process, (ii) circuit reliability improvement process and (iii) maintenance process;"[13]
3. Prepare, for each location with an identified upgrade, a location-specific service specification, identify capabilities that are required of incremental DERs to provide that service;
4. Compute, for each location, a project deferral avoided cost that could be attributed to incremental DERs that meet the required capabilities and apply the approved LNBA methodology to calculate LNBA results;
5. Execute these steps under two different distribution planning DER growth scenarios: (a) the Utilities' base distribution planning scenario and (b) the Very High scenario as filed in the July 2015 DRPs;
6. Make the results available via a heat map along with the DER growth scenario data on the Integration Capacity Analysis map;
7. Provide access to software and data used in Demo B and coordinate with the LNBA Working Group in monthly meetings and to coordinate with the Integrated Distributed Energy Resources (IDER) proceeding

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[9] ibid, at pp. A27-A28.
[10] For example, an energy storage device that reduces feeder peak load may have a negative energy avoided cost if the feeder peak occurs when CAISO prices are lower than the prices during charging times, see Locational Net Benefit Analysis Working Group presentation, July 26, 2016, at pp. 12-16.
[11] ibid, at pp. A25.
[12] ibid, at pp. A25.
[13] ibid, at pp. 28.

2.2 PG&E's Demo B Process and Deliverables

To meet the May 2, ACR requirements, PG&E:

1. Selected two DPAs: Chico and Chowchilla
2. Identified all distribution upgrade projects planned under PG&E's distribution capacity, reliability and maintenance programs in each DPA.
    a. Jointly with the other CA IOUs and in consultation with the LNBA WG, adopted the IDER Competitive Solicitation Framework Working Group's (CSFWG's) final consensus list of distribution services that DERs can potentially provide
3. Prepared, for distribution upgrades that provide one or more of the services which DERs can potentially provide, a location-specific capabilities specification for incremental DERs to defer that upgrade
4. Jointly with the other CA IOUs, developed a public LNBA Tool which was used to calculate a total avoided cost for all locations within each DPA, including T&D upgrade deferral avoided cost for locations with a deferrable upgrade
5. Evaluated changes to the projects and specifications identified in steps 2 and 3 above when PG&E's base DER growth scenario used in distribution capacity planning[14] is replaced with the Very High DER growth scenario PG&E filed in its 2015 DRP
6. Developed a public heat map and downloadable dataset which provides, for both DER growth scenarios, indicative LNBA results for all locations in each DPA as well as DER growth scenario data

Subsequent Chapters detail how PG&E executed each step and fulfilled the Commission's requirements for Demo B, including methods and inputs used to calculate LNBA results and develop the DER requirements for each deferrable project as well as discussion of results and lessons learned. Appendix 3 maps, at a detailed level, the location where each ACR requirement is addressed in this report or other Demo B deliverable.

In addition to this report, the final deliverables for Demo B include the LNBA tool and a heat map (and the underlying dataset in machine-readable format) that displays Demo B LNBA results and DER growth scenario data. These latter deliverables are briefly described below with further detail in Appendixes 1 and 2, respectively.

2.2.1 LNBA Tool

The three IOUs jointly engaged E3 to develop a technology-agnostic Excel tool for estimating location-specific avoided costs of DERs in Demo B. This LNBA Tool is based on the May 2, 2016 ACR's "primary" LNBA methodology framework described above; however, the LNBA Tool is designed to easily incorporate many refinements, including several that are reflected in the secondary analysis.

The LNBA Tool has two major parts: a project deferral benefit module, which calculates the value of deferring a specific capital project, and a system-level avoided cost module, which estimates the system-

[14] Per the revised May 2, ACR, PG&E used its most current distribution planning DER scenario for the base DER Growth Scenario.

level avoided costs given a user-defined DER solution. For any DER solution, expressed as an hourly DER profile, each module provides quantitative results. The summation of results from both modules provides an estimate of the total achievable avoidable cost for a given DER solution at a specific location.

The project deferral benefit module requires various capital project assumptions including project deferral requirements (e.g. duration, scale, and time of need).[15] Further discussion of inputs, sources and deferral value calculation methodology is provided in Chapter 8.

Since the precise deferral value results are considered market-sensitive information, for the purpose of Demo B, the IOUs do not provide precise deferrable project costs, and provide only indicative deferral values for each deferrable project listed in Chapter 5.[16]

The system-level avoided cost module calculates the estimated value of system-level avoided costs that exist for delivery of energy at any point on the system based on user-provided DER inputs. Since these avoided costs in Demo B are not location-specific, they will not vary within the Demo B DPAs.[17] Further discussion of system-level avoided cost inputs, sources and methodology is provided in Chapter 9. Avoided societal and public safety costs were not quantified in the LNBA Tool for Demo B; however, consistent with Commission guidance,[18] a qualitative description of societal and public safety benefits is included in Section 9.7.

2.2.2 Heat Map Overview

The heat map associated with Demo B provides a visual depiction of Demo B's LNBA results calculated using the project deferral module of the LNBA tool. Each feeder is color coded to provide indicative LNBA results according to the following key:

Table 2: Demo B LNBA Results Heat Map key

$	Indicates only system-level avoided costs and no T&D deferral value
$$	Indicates system-level avoided costs plus 0 to < 100 $/kW deferral value
$$$	Indicates system-level avoided costs plus 100 to < 500 $/kW deferral value
$$$$	Indicates system-level avoided costs plus > 500 $/kW deferral value

[15] Locational Net Benefits Analysis Working Group presentation, November 16, 2016, at pp. 18-23.
[16] See Decision (D.)16-12-036 Addressing Competitive Solicitation Framework and Utility Regulatory Incentive Pilot, p. 28 and Conclusion of Law 28 December 22, 2016, "To ensure fair competition, market participants should be excluded from any Distribution Planning Advisory Group discussions regarding market sensitive information, as established in Decision (D.) 06-06-066, especially the potential distribution costs that may be avoided by distributed energy resources." "[E]stablished policy in D.06-06-066 protects the confidentiality of market sensitive materials. Thus, any such materials, including the avoided cost of the deferred traditional investment, will not be disclosed in the solicitation package." Ibid. at 34. Available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M171/K555/171555623.PDF
[17] Locational Net Benefits Analysis Working Group presentation, November 16, 2016, at pp. 18-23.
[18] ibid, at pp. 27, "Societal Avoided costs…. Values or descriptions of these benefits"

Results for the heat map are provided in six layers consisting of three time periods—short, medium, and long term, as directed by the Commission[19]—each depicted under two DER growth scenarios. There are two additional layers that map the two DER growth scenarios themselves to the DPA.[20] The Demo B heat map is on the same platform as the integration capacity analysis (ICA) map, enabling users to access ICA and LNBA data through the same interface. Additional detail and a link to PG&E's heat map are provided in Appendix 1.

2.2.3 Demo B Coordination with the LNBA Working Group

LNBA Working Group (WG) was formed as a result of the May 2, 2016 ACR. Consistent with the ACR, the IOUs jointly engaged the LNBA WG in monthly discussions on Demo B. All major joint IOU decisions and approaches in Demo B were taken in consultation with the LNBA WG. In particular, the LNBA WG expressed strong support for using technology-agnostic approaches to evaluating location-specific benefits in Demo B. The methods and tools reflected in this report are therefore designed, to the maximum extent possible, to easily evaluate any DER or combination of DERs.

3 Electric T&D Services in Demo B

In quantifying the T&D component of LNBA in Demo B, section 4.4.1(A) of the ACR requires the IOUs to identify the full range of electric services that result in avoided costs for all locations within the DPAs selected for analysis. The values must include electrical services associated with distribution grid upgrades identified in (i) the utility distribution planning process, (ii) circuit reliability improvement process and (iii) maintenance process.[21]

The LNBA methodology proposed by the Commission requires the IOUs to consider the full range of electric T&D services that DERs can potentially provide. To quantify the potential reduction in investment costs and to ensure sustainability and reliability of services, each service should also be compared to the conventional "wire-based" methods of providing that same needed service.

Generally speaking electric services are associated with three core functions:

- Utility distribution capacity planning processes
- Circuit reliability/resiliency improvement processes, and
- Safety/maintenance processes

In order to investigate the type and value of the services that can be provided by DERs, each service will be characterized from the following perspectives:

- How the service is provided today (i.e. conventional method)
- How DER can provide the service

[19] ibid, at pp. 28, "….upgrade needs…should be in three categories that correspond to the near-term forecast (1.5-3 year), intermediate term (3-5-year) and long-term (5-10 year) or other time ranges, as appropriate"
[20] *DRP Demo B – Mapping Requirements*, September, 28, 2016, p. 2.
[21] Ibid, at pp. A29

Several factors may limit the ability of DERs to provide reliable electric services. These factors need to be carefully addressed and evaluated during design and deployment stages, including:

- Impact on the conventional engineering practices, such as impact on the protection design; change in protection methodology due to fault current reduction; protection desensitization; significant change in the voltage level; observability issues due to load masking; and forecast accuracy
- Technology advancement and system requirements to realize the service and prevent any adverse impact on the grid
- Performance certainty (performance requirements, criteria and availability)
- Current regulatory barriers or safety-related rules to the operation of DERs may not allow them to achieve full value

The following sections describe the electric T&D services, grouped by the potential role of DERs to provide these services: Services that DERs can potentially provide in Demo B, services that DERs are not assumed able to provide in Demo B but may be able to provide in the future, and services that DERs cannot provide today.

3.1 T&D Services that DERs Are Able to Provide in Demo B

The joint IOUs, in consultation with the LNBA WG, adopted the consensus list of four T&D services that DERs can potentially provide from the IDER CSFWG final report.[22] Each is described below.

3.1.1 Transmission and Distribution Capacity Deferral

DERs can reduce the thermal loading on all components of the electrical grid. In a radial network, thermal loading is reduced between the DER's location and the location of the existing source(s) of generation as long as the DER does not cause excessive reverse power flow. By reducing the load on the distribution system, a DER may alleviate the need to construct additional electrical infrastructure and allow existing equipment to feed more loads. To accomplish this, a DER must deliver energy at the time of peak load, reducing the maximum electrical demand on existing system components. As the cost for the grid's existing capacity has already been realized by ratepayers, the reduction in electrical demand facilitated by a DER does not necessarily result in value for utility customers.

In order for the DER to have real value for customers, it must defer a future capital investment(s); in this case, an investment needed to increase T&D capacity.[23] If the DER capacity enhancement fails to defer future investment(s), there is simply no added value for utility customers. However, when a DER does defer utility expenditures of some kind, the DER creates added value equal to the time value of money that the utility would have charged its customers for the original capital project. The T&D deferral module developed by E3 in conjunction with working group will serve as a calculator for these values. For a full explanation of the module please refer to Chapter 8.

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[22] *Competitive Solicitation Framework Working Group Final Report*, August 1, 2016. Available at: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=12212

[23] Sometimes T&D capacity is used interchangeably with thermal capacity, since it is largely a function of equipment ratings that are based on equipment temperatures above which damage may occur.

3.1.2 Voltage support

DERs can potentially provide voltage support in areas where customers experience low/high voltage conditions outside of Rule 2 limits. Voltage support services are planned capital investments needed to correct excursions outside voltage limits and supporting conservation voltage reduction strategies in coordination with utility voltage/reactive power control systems. .

Typically, the utilities mitigate low voltage issues by adjusting transformer settings or installing resources capable of increasing or reducing voltage, such as substation load tap changers, line voltage regulators, voltage boosters and capacitors.[24] . DERs can provide a benefit to utility customers if they are able to defer or eliminate a capital investment required for voltage control, such as a new capacitor bank or voltage regulator.

DERs may potentially provide voltage support for the grid in two different ways. First, if the unit operates within the requirements defined in Rule 21 for smart inverters, it can contribute to local voltage control via the injection or absorption of reactive power by power electronics. This feature could be used to both increase and decrease voltage. Second, DERs could reduce the net load and thereby decrease the voltage drop experienced across a distribution feeder.[25]

The value of the voltage support service is directly determined by the deferral value of a planned voltage support project. As with deferred capacity projects, the deferral value is driven by the time value of money realized by deferring an investment. As long as voltage remains within the Rule 2 limits there is no need for a voltage support investment, and hence no costs for DERs to avoid.

In Demo B, voltage support project deferral requirements are expressed in terms of load reduction rather than reactive power injection or absorption. This ensures that non-inverter-based DER technologies such as energy efficiency are able to be evaluated as DER solutions to deferrable voltage support projects.

3.1.3 Reliability - Back-tie

The back-tie service creates value by deferring an upgrade to a back-tie switch. This is a switch used to improve restoration of service in abnormal grid conditions, such as a fault on a distribution line. In order to ensure reliable service within a distribution system, it is desirable to have a back-up tie installed such that it can be used to transfer the load from the faulted feeder to an adjacent feeder with available capacity. However, the capacity of a tie switch maybe limited and may not be sufficient to accommodate the additional power required by the customers on the faulted feeder. One traditional method to resolve the limited capacity is to employ higher rated infrastructure (e.g. higher rated back-tie switches or additional back-tie lines). DERs can provide a benefit if they are able to defer or eliminate a future capital investment required to increase back-tie capacity.

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[24] Substation LTCs are devices that change the tap position on power transformers to adjust output voltage on the low-voltage side of the transformer; line voltage regulators are line transformer banks that use a series of tap positions to adjusted the voltage up or down to maintain an predetermined output voltage; line capacitors provide a source of reactive power to reduce line losses and increase line voltage.

[25] The root cause of many voltage problems is often excessive loading of sections of distribution line, even when the thermal rating of that line may not be exceeded.

The DER alternative would include installing DERs downstream of the constrained tie switch, thus reducing the load transferred in the event that the transfer switch is closed. The load reduction would be such that an existing (lesser rated) tie would be able to feed some greater amount of load. Similar to the other T&D deferral services, the value of this service would be equal to the time value of capital that would have been spent on a project to improve the rating of the tie to achieve the required transfer capability without the DERs installed.

3.1.4 Resiliency via Microgrid

In order to provide electric services reliably, it is highly desirable to have an alternate power source in case distribution outages occur. As referenced in the previous section, utilities usually design their distribution systems such that all circuits have back-ties to adjacent circuits in order to provide another source from the grid. The redundancy in power sources allows system operators to "cutover" load in the event of a planned or unplanned outage.

An alternative to back-ties is a microgrid. A microgrid essentially provides the same service as a back-tie by enabling a portion of the distribution system to be isolated and powered by its own internal generation. During an outage, microgrids provide more reliability than back ties, in that they do not leave customers vulnerable to larger system outages (e.g., a substation or transmission line outage). However, because substation and transmission outages are rare, the minor increase in reliability brought about by microgrids does not justify their added cost in most areas.

In remote areas, however, the cost for providing redundancy through a "wires" method can be much more expensive, making microgrids a potential alternative to meet reliability needs in these areas. DERs could potentially provide a local microgrid service, consisting of several DERs that feed customers until normal grid service is restored. In order to provide this service, the DERs in combination with a microgrid control system need to have "islanding and load following" capability, which is not the case for the vast majority of DERs subject to the typical interconnection process. Depending on the ownership structure and customers' involvement, the safety, integrity and duration of the service become critical challenges that require in-depth investigation.

3.2 T&D Services that DERs Are Not Assumed to Provide in Demo B but May Provide in the Future

For the purposes of Demo B the only services that DERs can potentially provide are described in the prior section. Here we address the services that DERs have the potential to provide, but are not assumed to provide them in Demo B. Limitations on DERs' ability to provide these services may be based on insufficient information (e.g. equipment life extension) or insufficient control infrastructure (e.g. VVO) or lagging regulatory processes (e.g. frequency regulation).

3.2.1 Grid Visibility and Situational Intelligence

This service was identified as a non-consensus DER service in the IDER CFSWG Final Report. While not formally defined there, an example is provided: making second-by-second measurements of conditions at the grid available. Further work to define this service is clearly needed.

3.2.2 Conservation Voltage Reduction (CVR) and Volt/VAR Optimization (VVO)

The IOUs were directed to "include opportunities for conservation voltage reduction and volt/VAR optimization" in Demo B.[26] CVR and VVO are also identified as a second non-consensus DER service in the IDER CSFWG final report. [27]

CVR refers to the ability of devices, including certain DERs, to maintain voltage levels at the lower-end of the range of acceptable voltage levels. Doing so can reduce the electrical consumption of certain customer end use devices without a noticeable change in performance. CVR is often a byproduct of Volt/VAR Optimization – a general term for more precisely monitoring and controlling line voltages.

On a typical distribution circuit, voltage is controlled by distribution devices at the substation or on distribution lines as described earlier. As a standard practice, the IOUs currently set these devices to deliver as low a voltage within the acceptable range as possible.[28] Additional CVR savings beyond those achieved by standard practice may be achieved by more sophisticated voltage controls, such as those that enable VVO.

Quantifying this potential additional savings on any particular circuit requires understanding the extent to which CVR has already been achieved under standard practice. Any incremental CVR benefits beyond standard practice are highly dependent on a variety of factors specific to that circuit and the customer end use devices that are on that circuit.

For Demo B, CVR benefits associated with any DER can easily be incorporated in the DER load reduction assumptions used to develop the Hourly DER Profile input to the LNBA tool. One simple method to estimate CVR energy savings is to use the CVR factor, which is the ratio of percent energy savings to percent voltage reduction: [percent energy savings] = [CVR Factor] x [percent voltage reduction].

The percent voltage reduction is largely a function of the starting voltage and circuit configuration. The CVR factor is largely a function of the type of customer end use devices on the circuit. In Demo B, the IOUs have not done the engineering analysis and field research to estimate these quantities; however, a benchmarking exercise summarized in PG&E's 2017 GRC found that prior studies indicate a range of 0.76 to 4 for average voltage reduction percent and a range of 0.06 to 2.7 for the CVR factor.[29]

3.2.3 Equipment Life Extension

DERs may extend the lifespan of distribution equipment. Specifically, the reduction in thermal stress facilitated by DERs that reduce loading may extend the life of electrical insulation (e.g., cable jacketing or transformer oil/paper winding insulation) which in turn may lead to longer electrical equipment lifetimes.

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[26] ibid, at pp. 30

[27] A third such item, Reactive Power support, not included here as it generically refers to a capability that can enable voltage support service described in section 3.1 as well as CVR/VVO and power quality services in section 3.2.

[28] For example, PG&E's Rule 2, section 2.1 states "for the purposes of energy conservation, distribution line voltage will be regulated to the extent practicable to maintain service voltage… on residential and commercial circuits between 114 V and 120 V," available at: http://www.pge.com/tariffs/pdf/ER2.pdf

[29] See PG&E 2017 GRC Phase I Workpapers Table 13-22.

However, the correlation between thermal stress and insulation lifespan are currently poorly characterized, making it difficult to accurately quantify the potential role of DERs in extending equipment life. Furthermore, at present, most electrical equipment is replaced for reasons unrelated to insulation or conductor failure (e.g, service upgrades, corrosion, bad connections, and new protection schemes).

The majority of equipment replacement needs are identified in the utility corrective maintenance program, only a small percentage of which are related to damage from loading. Because most equipment replacement is unrelated to insulation/conductor failure, potential savings in the realm of equipment life extension are relatively small compared to the more tangible benefits of DERs quantified in Demo B.

To the extent that loading levels impact equipment life, these effects would also apply to load-increasing DERs and generating DERs at very high penetration, which could negatively impact equipment life by increasing net loading on equipment subject to significant amounts of backflow.

Finally, DERs which result in highly variable net loading can potentially also result in reduced equipment life by increasing the number of operations of line regulators, capacitors and load tap changers, or by creating larger thermal stresses through more rapid load changes.

Further study to fully understand the correlations between DER impacts and equipment life is needed. The utilities see such inquiry as an opportunity of interest in the long term refinement.

3.2.4 Bulk Power System Ancillary Services (AS)

Ancillary Services includes frequency regulation, spinning reserve, and non-spinning reserve. In contrast with all other potential services in this section, avoided AS is included in LNBA as defined for Demo B. Per commission guidance, the IOUs adopted the E3 DERAC estimates of avoided AS.[30] This section describes the potential for DERs to directly provide these grid support products through the California Independent System Operator (CAISO) markets.

The CAISO currently has nascent programs that allow aggregated DER or large DER to participate in its existing market for these system support services, and the CAISO has many stakeholder processes underway to better accommodate market-participating DERs; however, at this point DERs are not assumed to directly provide these services in Demo B.

[30] ibid, p. 27, “Avoided Ancillary Services… Use DERAC values”

Frequency regulation

Frequency regulation (Reg.) is the provision of energy to the CAISO at the timescale of seconds, which is used by the CAISO to manage Area Control Error caused by imbalance between demand and supply at the interconnection level.[31]

The "frequency-Watt" function is a feature that can be offered by the new generation of inverter-based DERs (smart inverters) to provide fast frequency regulation in milliseconds. The "frequency-watt" mode enables the smart inverter to mitigate frequency deviations by injecting/absorbing active power. This mode can be used either in emergency situations (when a large frequency deviation causes system instability) or in normal situations (to smooth out minor frequency deviations).[32]

Spinning Reserve

Spinning Reserve is the on-line reserve capacity synchronized to the grid system, ready to meet electric demand within 10 minutes of a dispatch instruction by the ISO. Spinning Reserve is needed to maintain system frequency stability during emergency operating conditions.

Some DER technology types will be able to provide spinning reserve and some will actually serve to increase spinning reserve requirements. Various energy storage technologies and demand response are likely to be able to provide this service.[33] On the other hand, high penetration of distributed PVs can increase the spinning reserve requirements of the system.[34]

Non-spinning Reserve

Non-Spinning Reserve is off-line generation capacity that can be ramped to capacity and synchronized to the grid within 10 minutes of a dispatch instruction by the ISO and is capable of maintaining that output for at least two hours. Non-Spinning Reserve is needed to maintain system frequency stability during emergency conditions. The barriers to including non-spinning reserve in the LNBA are the same as the frequency response and spinning reserve services.

3.2.5 Power Quality

The utilities provide electric service within power quality planning limits defined by utility guidelines and applicable industry standards for Total Harmonic Distortion (THD), voltage sags/swells, fast transients, voltage unbalance and flicker. Balancing voltages, canceling harmonic distortion, managing voltage

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[31] CAISO procures Reg. UP and Reg. DOWN as separate products in Day Ahead (DA) and Hour Ahead (HA) markets, instructing qualified/awarded generators on a 4 second basis to provide Reg. UP or Reg. Down services. Payments are made per the DA and HA cleared prices. Actual net energy delivered over the hour is settled at the balancing energy price, as determined by the Real Time (RT) Market price. There is also a Pay for Performance tariff that rewards generators for accuracy in response - this tends to favor faster resources, such as fast energy storage devices.

[32] Distributed Energy Management (DER): Advanced Power System Management Functions and Information Exchanges for Inverter-based DER Devices, Modelled in IEC 61850-90-7.

[33] For instance, energy storage system increases the available reserves on the system without decreasing conventional generators' efficiency. By setting a minimum discharge level, the distributed energy storage can always provide some capacity as spinning reserve.

[34] For example, when there is a rapid frequency drop (e.g. due to a generator outage) and the spinning reserve is required, small-scale PV will likely trip off due to the prevailing inverter anti-islanding. Therefore, the frequency drop is exacerbated and the need for reserve is increased.

sag/swell and flicker are all part of normal distribution operations. This suite of power quality services that DERs may be able to provide is described below.

These services are distinct from the voltage support service described in section 2.1, in that power quality service refers to very fast device responses that are required to mitigate dynamic voltage issues at very short timescales.

Total Harmonic Distortion (THD)

Some DERs may lower system impedance; the lower impedance of the combined system with respect to harmonics results in lower voltage distortion and THD from the nonlinear loads. This benefit is likely as long as the DER is not a significant source of harmonics.

Voltage sag

If the DER is installed near the end user equipment, it can help mitigate momentary voltage drops resulting from in-rush currents – voltage sag.[35] This would be considered a service of value if voltage sag drives customer voltage below the lower limit of ANSI C84.1 Range A. Conversely, DERs could extenuate the need for this service if the DER trips offline during voltage sags, driving voltage even lower than the pre-DER conditions.[36]

Voltage swell

Voltage swell is the opposite of sag: a momentary voltage increase. DERs may be able to absorb load and thus limit voltage swell to suitable ranges. The Presence of DERs, however, can also lead to additional temporary overvoltage (voltage swells). The following table describes the scenarios DER can affect negatively on voltage swells.

Table 3: Impact of DER on voltage swells

PQ Category	Description of PQ Issue and Likely Positive or Negative Impacts of DR	Power Conversion Systems
Voltage Swell	**Negative** - Certain transformer connections for DR can cause voltage swells on healthy phases during line-to-ground faults during islanding.	Wye/ungrounded wye, delta/ wye, delta/delta, wye/wye with an ungrounded generator
Voltage Swell	**Negative** - Voltage swells and ferroresonant overvoltages can occur due to resonance between the DR impedance and distribution capacitors during islanding.	All
Voltage Swell	**Negative** - Out-of-phase reclosing between the utility system and an islanded DR may cause transient overvoltages.	All

Voltage Unbalance

DERs can either aggravate or improve voltage unbalance. The table below summarizes different scenarios in which DER can impact the voltage unbalance situation.

[35] A minor version of this is observed when lights dim the same moment an appliance with an electric motor starts
[36] Grid Reliability and Power Quality Impacts of Distributed Resources, EPRI Technical Update, W. Steely, March 2003.

Table 4: Impact of DER on Voltage Unbalance

PQ Category	Description of PQ Issue and Likely Positive or Negative Impacts of DR	Power Conversion Systems
Voltage Unbalance	**Negative -** Existing feeder voltage unbalance can cause machine connected DR to trip on current unbalance or cause rotor heating due to high negative-sequence currents.	Synchronous Generator or Induction Generator
Current Unbalance	**Negative -** Depending on the winding arrangement of the DR interconnection transformer, feeder current unbalance will be reflected in the interconnection transformer causing overload and possibly damage if the transformer is not protected.	grounded-wye/delta and grounded-wye/grounded-wye transformer (with the generator grounded).
Voltage Unbalance	**Positive -** In cases where the DR feeds a constant power into utility distribution feeders, the lower phase voltage will see a relatively higher current and a consequently a tendency to raise the voltage.	Synchronous Generator or Self-Commutated Inverter

Voltage flicker

Some DERs may be able to provide voltage smoothing function to reduce voltage flicker experienced by customers. Many DERs however, can cause more voltage flickers to occur. Voltage fluctuations can cause flickers visible to human eyes. This results in lamps to change their light intensity or flicker. Stopping or starting a DER can lead to sudden voltage fluctuations which in turn could lead to more adverse voltage conditions. The table below describes the ways DER affect negatively on voltage flicker.

Table 5: Impact of DER on Voltage Flicker

PQ Category	Description of PQ Issue and Likely Positive or Negative Impacts of DR	Energy Source/ Prime Mover
Flicker	**Negative -** Low RPM, low number of cylinder machines applications or misfiring engines can cause voltage fluctuation.	Reciprocating Engine
Flicker	**Negative -** Cloud caused irradiance changes could produce flicker.	Photovoltaic
Flicker	**Negative -** Fluctuations in the wind speed, pitching/yaw error in blades, wind shear, and tower shading can produce flicker.	Wind Turbine/Generator

In exceptional cases, customers may request premium power quality services that can be provided through overall circuit level enhancement or managed locally (e.g. by installing filters or relocating capacitor banks). As long as service levels remain within standard ranges, there is no need for power quality services.

If there is a need, a DER that can offset that need would be valued for the avoided cost achieved through deferral of the conventional project that would have met the power quality need. Therefore, the value of these services can be accounted for in the deferral module. However, as detailed above, DERs may have both negative and positive implications on common power quality issues. Additional analyses are needed to clarify the net benefits of DER on power quality.

3.2.6 Downsizing of New or Replacement equipment

This service is a variation on transmission and distribution capacity deferral described in Section 3.1. In this case, rather than reducing cost by affecting the timing of an investment, DERs may be deployed to reduce the amount of an investment by enabling a particular needed device to be downsized. More study on distribution investment sensitivity to equipment size and other factors influencing equipment sizing decisions is needed to evaluate this potential benefit.

3.3 T&D Services that DERs Are Assumed Unable to Provide In Demo B and in the Future

This section highlights distribution services that are considered non-deferrable for Demo B, and are not expected to be services that DERs can provide in the future.

3.3.1 Repair or Replacement

Utility Equipment is generally repaired or replaced to address service upgrades, corrosion, external damage, and/or new protection schemes. For example, equipment and structures need to be replaced after damaged by car contact, vegetation damage, or simply degradation over time.

3.3.2 Reliability (Non-Capacity Related)

Section 2.1 detailed reliability improvements that DERs can potentially provide. However, other utility costs that improve reliability (non-capacity related projects, including the installation of new sectionalizing equipment, sensors, fault detection, and emergency preparation/response initiatives) cannot be provided by DERs. Many of these projects include fixing standards violations or replacing degraded wires. These costs will exist regardless of DERs installed on a distribution network.

3.3.3 Operations and Maintenance

Maintenance is required to continue the healthy operation of equipment. Operations and Maintenance costs will exist regardless of DERs installed on a distribution network, as long as customers require power delivery through the electrical grid. There is no mechanism for DERs to defer the need to maintain existing equipment. The only exception is O&M associated with a new piece of equipment that is deferred as described in Chapter 9.

3.3.4 Emergency Preparation and Response

The utility's ability to restore service after outages is not assisted in any way by DERs. These projects often require equipment installation in preparation for an emergency, the replacement of damaged equipment during/after an emergency, or strategies to dispatch service personnel more efficiently. These projects need to be designed and activated in a very short time frame, and simply cannot be met through DER sourcing efforts. As such, costs associated with improving emergency response are not avoidable by installing DERs.

3.3.5 New Business/Work at the Request of Others

These projects entail the installation of necessary infrastructure to serve new customers. If there is a lack of existing infrastructure, new customers cannot consume or produce energy. DERs do not mitigate the need to connect new customers to the grid.

4 Distribution Planning and Selected Planning Areas

Since Demo B relies on the planned upgrade projects that result from PG&E's distribution planning process as the primary input to the T&D benefit analysis, understanding the planning process and the forecasting work that drives it is helpful.

The sections below provide an overview of the load forecasting process used for distribution planning and for the DER scenario development process and provide an introduction to the two planning areas chosen for Demo B – Chico and Chowchilla – including a discussion of load and DER growth scenarios for each area.

4.1 Load Forecasting in Demo B

PG&E provided a detailed description of its distribution load forecasting methodology in the July 1, 2015 Distribution Resources Plan;[37] this section draws from and expands upon that description.

Each year, PG&E's distribution engineers forecast the magnitude and location of load growth to ensure that adequate distribution capacity is available to meet peak demand in a 1-in-10 weather year[38] at all locations on the distribution system. PG&E's distribution service territory consists of over 3,000 feeders and 1,300 distribution transformer banks assigned to roughly 250 DPAs.

PG&E uses the LoadSEER[39] distribution load forecasting tool to prepare a 10-year growth projection for each feeder and substation transformer bank. This analysis uses historical load and temperature data, geospatial economic and demographic factors and imagery, customer class information, and allocated system-level forecasts – primarily an allocation to each acre in PG&E's distribution service territory of the annual peak load growth adopted in the California Energy Commission's California Energy Demand base case scenario .

A significant amount of analysis is performed to normalize historical data, to convert between simultaneous and non-simultaneous peak forecasts for each circuit, and to adjust forecasts using local knowledge such as new known loads, firm capacity agreements or large generators.

PG&E uses its load forecasting process to forecast feeder and substation transformer bank load growth 10 years into the future in order to develop investment plans and expenditure estimates for future capacity additions.

As described in its DRP, PG&E updates the load forecast annually to capture changes on the distribution system, which can be very dynamic: loads and hence load forecasts change over time and the system configuration is constantly changing as new customers are connected, assets are replaced and device settings are changed. Consequently, distribution investment plans change from year to year.

From a detailed capacity planning perspective, PG&E typically identifies new feeder projects approximately one-to-two years in advance and new substation transformer projects approximately

[37] PG&E Electric Distribution Resources Plan Filing at pp. 16-21 and Appendix B (July 1, 2015). Available at: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M152/K961/152961243.PDF

[38] This is the peak load in a year with 90th percentile high temperatures, a common standard used in power system planning.

[39] Additional detail on the LoadSEER tool is provided in the PG&E's Demonstration A Implementation Plan.

two-to-three years in advance. Forecast results beyond 5 years are generally considered informational, except that they may be used to identify potential needs for new substations, which can have long lead times due to permitting and land acquisition processes.

4.2 DER Scenarios in Demo B

For PG&E's 2017 distribution planning cycle, the forecast described above does not include impacts of DERs that are forecasted for future years – i.e. it is a gross load forecast. Future DERs are accounted for in a separate step. [40]

Accounting for the impacts of DERs is a critical component of the distribution planning process, as these resources can both increase or decrease load on distribution feeders and substation transformer banks. Hence DER growth assumptions impact the planned upgrade projects which form the basis of Demo B T&D benefits.

As noted in section 2.1, the commission directed the IOUs to use two different DER growth scenarios: a) the base scenario used in distribution planning and b) the very high scenario filed in the IOUs' July 2015 DRPs. This section describes how these DER scenarios are incorporated into the distribution planning forecasts used in Demo B, and it applies to both DER scenarios.

PG&E provided a detailed description of its DER scenario development and locational allocation methodology in the July 1, 2015 Distribution Resources Plan,[41] this section draws from and expands upon that description.

In PG&E's DRP, scenarios were created for the DER categories listed below[42]; however only certain of these were included in Demo B. The table below indicates which DER categories were included in Demo B and the logic behind excluding the others.

Table 6: DER Types Included in Demo B DER Growth Scenarios

Type	Included In Demo B DER Scenarios?	Reason for Exclusion
Energy Efficiency	Yes	N/A
Demand Response	No	Deployment of event-based programs may not coincide with local peaks
Retail DG: Solar PV	Yes	N/A
Retail DG: CHP	No	These large DG units are difficult to reliably forecast at a locational level.
Retail DG: Fuel Cells	No	
Retail Energy Storage	No	Lack of data makes this new technology difficult to forecast at a locational level and discharge cycles may not coincide with local peaks.
Plug-in Electric Vehicles (EVs)	Yes	N/A
Feed–In-Tariff CHP	No	These large DG units are difficult to reliably forecast

[40] Impacts from existing DERs are simply embedded in the historic data used to generate the gross load forecast described previously.
[41] at pages 90-133 and Appendix C
[42] July 1, 2015 DRP filing page 92

Wholesale Solar and Biomass	No	at a locational level.
Wholesale Energy Storage	No	Larger units are difficult to reliably forecast at a locational level, especially given available data, and discharge cycles may not coincide with local peaks.

In order to account for the three DER categories included in Demo B under the two required Demo B DER growth scenarios, a feeder-level geospatial allocation process was completed as summarized in the table below:

Table 7: DER Growth Scenario Summary

Category (Scenario)	**System-level Quantity**	**Geospatial Allocation Process**	**Hourly load impact profile**
EE (PG&E base scenario)	2015 IEPR AAEE Mid-Mid Scenario	CEC busbar-level allocation, then allocated to feeders based on customer segments and/or prior adoption patterns.	Proportional to customer load shape by segment.
EE (DRP very high scenario)	2015 IEPR AAEE High-Mid Scenario		
Retail DG PV (PG&E base scenario)	PG&E internal analysis	Multivariable regression based on key adoption drivers (e.g. customer type, consumption, geographic and building characteristics).	PG&E system-wide typical shape
Retail DG PV (DRP very high scenario)	PG&E 2015 IEPR Form 3.3 + impacts of additional policy and cost drivers[43]		
EV (PG&E base scenario)	PG&E 2015 IEPR Form 1.1(a)	County-level allocation based on rebate program data, then allocated to feeders based on customer segments and/or prior adoption patterns	Weighted average of home-TOU, home-non-TOU, and workplace/public charging profiles[44]
EV (DRP very high scenario)	Trajectory to half car and truck fossil fuel use by 2030 per Governor goal		

The feeder-level quantities and profiles for each DER category is then used as an input to the LoadSEER forecasting tool, which then applies the appropriate DER load adjustment to the gross load profiles at each feeder and transmission substation bank. This process is repeated for the component parts of each DER growth scenario. Feeder-level DER data is available via the PG&E Demo B heat map, and additional detail on that data is provided in Appendix 1.

4.3 Chico and Chowchilla

PG&E selected Chico and Chowchilla DPAs for Demo B to meet the minimum requirements stated in Section 2.1 while also demonstrating the LNBA methodology in areas with a broad range of electrical

[43] Table 2-23 of PG&E's 2015 DRP details a variety of assumptions used to develop the Retail DG Very High scenario
[44] See pg. C-56 of PG&E's DRP.

characteristics. The locations of Chico (in blue) and Chowchilla (in red) are shown in the figure below, while the table which follows provides a high-level comparison of the two areas.

Figure 1: Selected DPA Locations

Table 8: DPA Characteristics

	Chico	Chowchilla
Location	Butte County (Urban/Suburban)	Madera County (Rural)
Substations	10	4
Feeder count by voltage	37 @ 12kV / 4 @ 4kV	20 @ 12kV
Customers	125,000	13,000
Recent Historical Peak	235 MW	140 MW
Customer Type	80% Residential, 5% Agricultural, 15% C&I	60% Residential, 30% Agricultural, 10% C&I

The decision to use Chico and Chowchilla for Demo B is in part driven by a desire to coordinate with Demo A, where capturing a range of electrical characteristics is especially important.[45] Coordinating these demonstration projects simplifies the implementation of Demos A and B, and also benefits external stakeholders, who will have a high-level of familiarity of these two, diverse areas once both demonstration projects are complete – in essence it is an opportunity to develop both broad and deep familiarity with PG&E's system through a close look at two DPAs.

The following sections provide additional detail on loads and DERs in Chico and Chowchilla, respectively.

4.3.1 Chico DPA

Chico Load

Discussions through 2016 regarding potential deferrable projects – namely two new transformer banks and two new feeders – were based on the 2016 load forecast and planning cycle results. Once 2016 peak loads were observed, consistent with the annual planning cycle, a 2017 load forecast informed by the most current load and system configuration information was created for this area.

The table below provides the most recent five years of recorded area-level loads

Table 9: Chico Load Data

Year	Chico DPA Sum of Recent Non-Coincident Feeder Peak Loads
2012	264 MW
2013	272 MW
2014	243 MW
2015	237 MW
2016	235 MW

Chico load growth trends have flattened in the current forecast compared to prior years' forecasts such that the capacity upgrades anticipated in prior planning cycles have been pushed out beyond the current 10-year forecast horizon. Based on the current forecast, all overloads that show up in the 10-year forecast horizon can be mitigated by transferring load to adjacent facilities without requiring any capital investment.

Many substation transformer banks in Chico are currently heavily loaded and, under the current load growth forecast, will remain heavily loaded into the future. Under these conditions, the planning process can be sensitive to fairly small changes in the load growth trends, resulting in significant changes to the timing and magnitude of projected overloads.

Furthermore, predicting loads in Chico is complicated by the nature of agricultural pumping loads, which account for a relatively small number of customers but relatively large portion of the overall load in certain areas. Agricultural pumping loads are highly sensitive to precipitation, groundwater conditions, water rights, crop changes and other factors which are difficult to account for in load forecasting, especially at the granularity of individual feeders and transformers.

[45] Additional detail on the range of electrical characteristics of the distribution system in Chico and Chowchilla is available in the Demo A final report.

Given the challenge of forecasting in this area, new overloads could emerge in the coming year or in future planning cycles; however the current forecast doesn't support conclusions about whether these possible future overloads could be mitigated with non-capital transfers or would require some capital investment.

For purposes of Demo B, one of the prior capital projects, Esquon Bank #2 installation, is presented along with the deferrable projects in section 4, although no deferral benefit is calculated, since it is no longer planned and since no load reduction requirement can be developed without an expected overload. This is a relatively small substation with significant agricultural loads that is presently loaded to over 90% of its normal rating under the current load forecast, hence it is therefore a location that may be overloaded in the future.

Chico DER Impacts

As described in Section 4.2, PG&E's used two DER growth scenarios to develop feeder-level DER impacts for Demo B. While a detailed dataset is available for each scenario by feeder and DER type, the table below provides a sense of the cumulative effect of DERs in the first and last years of the planning horizon.

Table 10: Chico DER Data

Year	Chico DPA Sum of Non-Coincident Feeder Peak Load DER Impacts
2017 (Base Case)	- 15 MW
2026 (Base Case)	- 86 MW
2017 (Very High Case)	- 27 MW
2026 (Very High Case)	- 120 MW

These MW numbers represent the combined impact of all DERs on each feeder at the peak time for that feeder summed across the DPA for the year indicated. As these are non-coincident sums, they are analogous to the load information provided above; however they are not easily translated to a nameplate capacity number.

As described in Appendix 1, these impacts are measured at the non-coincident feeder-level peak before DER impacts are accounted for on the timing of that peak, thus the very high DER impacts in later years may not capture the effective DER impacts on the true net load peak. As indicated in the refinements section, PG&E expects considerable advances to the current methods used to develop granular DER growth scenarios, especially for years in the latter half of the ten-year horizon.

4.3.2 Chowchilla DPA

Chowchilla Load

The 2017 Chowchilla load forecast, informed by the most current load and system configuration information, has largely followed the trajectory expected based on prior planning cycles. Once 2016 peak loads were observed, consistent with the annual planning cycle, a 2017 load forecast informed by the most current load and system configuration information was created for this area. The table below provides the most recent five years of recorded area-level loads.

Table 11: Chowchilla Load Data

Year	Chowchilla DPA Sum of Recent Non-Coincident Feeder Peak Loads
2012	127 MW
2013	138 MW
2014	146 MW
2015	150 MW
2016	140 MW

Chowchilla DER Impacts

The following table replicates Table 10 above for the Chowchilla DPA.

Table 12: Chowchilla DER Data

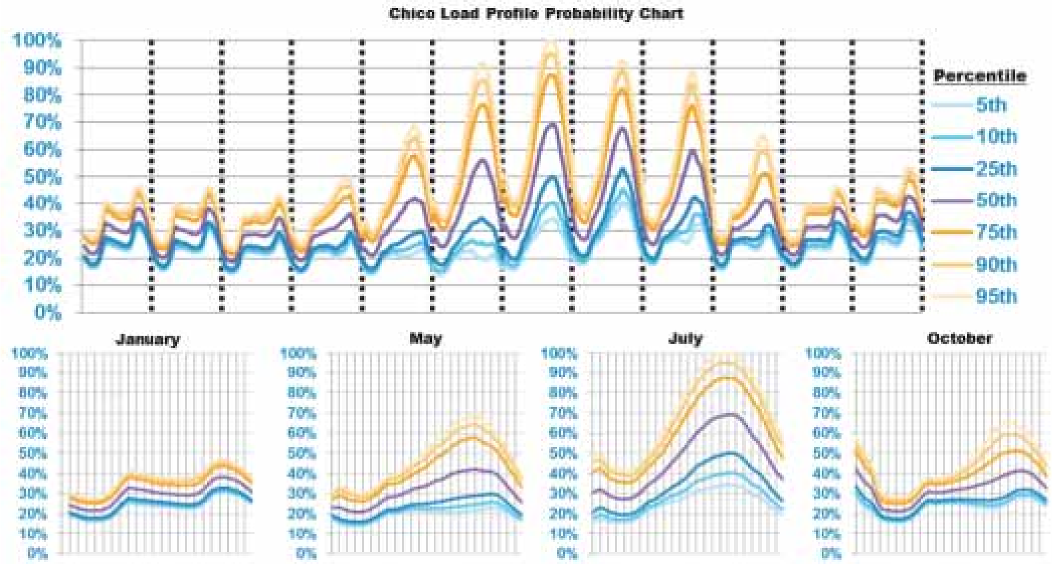
Year	Chowchilla DPA Sum of Non-Coincident Feeder Peak Load DER Impacts (MW)
2017 (Base Case)	-2 MW
2026 (Base Case)	-14 MW
2017 (Very High Case)	-3 MW
2026 (Very High Case)	- 30 MW

4.4 Putting it all together: Developing Net Load Shapes

In addition to understanding the nature of peak loading and DER impacts on peak loading across the feeders and substation transformer banks in Demo B, a detailed hourly load shape was required to develop load reduction requirement profiles for distribution project deferrals. A DER solution must not only mitigate the overloads on a feeder or transformer at the peak hour, but in any other hour with an overload.

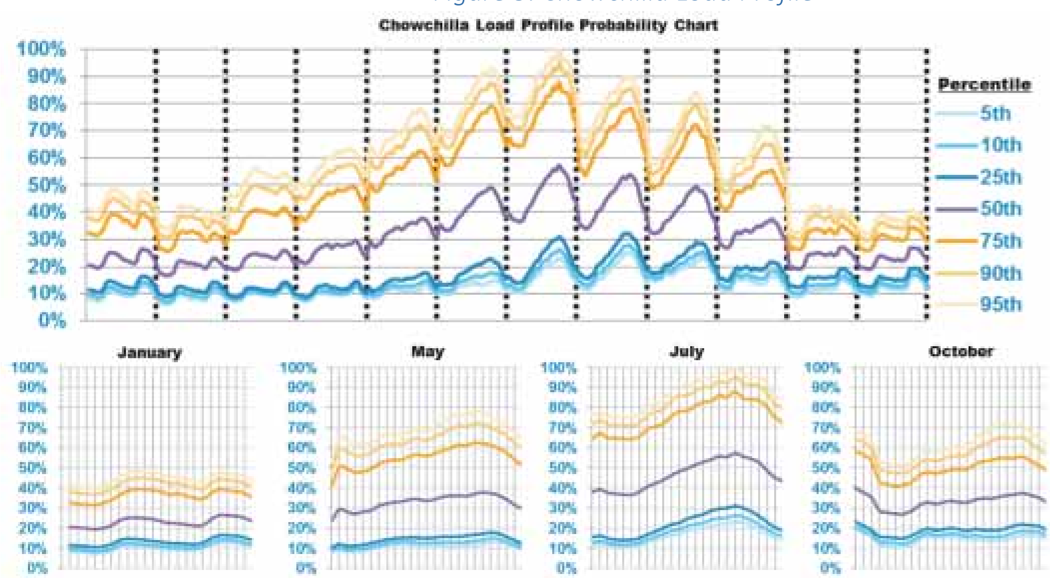
As with Demo A, PG&E used preliminary enhanced load profile data from the EPIC 2.23 project which is derived from recent hourly Smart Meter data for customers in each DPA. The load profiles below provide an aggregated profiles for Chico DPA broken down by percentile of loading level for each hour: the different percentile shapes show the probability of hourly load throughout the year as a percentage of the peak. Chico is representative of typical residential loading with summer peaking driven by temperature.

Figure 2: Chico Load Profile



Below is an analogous DPA-level, probabilistic load profile diagram for Chowchilla. This area's load shape is representative of rural loading driven by non-residential load, in particular agricultural loads.

Figure 3: Chowchilla Load Profile



For Demo B, PG&E used the 95th percentile load and DER profiles for each feeder or substation transformer bank to capture the hourly loads and DER impacts on days when a distribution facility is more likely to be overloaded. The feeder or substation bank load profiles were adjusted using the feeder or bank-level DER quantities and profiles described previously under the two required DER growth scenarios.

5 Description of Deferrable Upgrade Projects and Deferral Values In Demo B DPAs

Any project planned for 2018 or later that provides the services described in Section 3.1, T&D Services that DERs are Able to Provide in Demo B, was considered deferrable. Detailed information about each project and indicative deferral values are provided below by DPA. Projects planned for 2017 were not considered deferrable in Demo B.

The indicative deferral values provided below are based on the following tranche values, consistent with the heat map color scheme below.

Table 13: Demo B LNBA Results Tranches

$	Indicates only system-level avoided costs and no T&D deferral value
$$	Indicates system-level avoided costs plus 0 to <100 $/kW deferral value
$$$	Indicates system-level avoided costs plus 100 to <500 $/kW deferral value
$$$$	Indicates system-level avoided costs plus > 500 $/kW deferral value

These $/kW values are based on a three year deferral benchmark value that is used consistently across the IOUs. It is the total three-year deferral present value for a project divided by the maximum kW of required load reduction to achieve that three year deferral.

The "very high DER Growth Sensitivity" deferral results assume no re-scoping of projects. In reality, for projects more than two years out, if future planning cycles show trends toward this very high scenario, projects might be re-scoped, resulting in a different deferral value.

The DER deferral specifications, in the form of an hourly load reduction requirement, are summarized in the tables below in terms of magnitude, timing and year of need. A full ten-year hourly, load reduction requirement profile for use in the LNBA Tool is available for each project below in the downloadable data accessible through PG&E's Demo B heat map.

As stated earlier, expressing these requirements as an hourly load reduction requirement enables a technology-agnostic approach to LNBA by allowing any type of DER to potentially provide any type of service required for a deferral. For Voltage projects, this was achieved by adding increments of load reduction in an iterative power-flow model until the voltage problem was eliminated.

For all deferrable project load reduction requirements, PG&E's approach was to construct a requirement profile based on the maximum load reduction need by hour and day-type for a target deferral year, then apply that profile across all months with any amount of load reduction need.

5.1 Chico

As noted previously, the Esquon Bank 1 capacity upgrade is provided as a deferrable project example in Chico; however, PG&E’s current load forecast does not indicate a need for this project within the planning horizon.

Table 14: Chico Deferrable Project Summary and Results

Project Name	**Esquon Bank 1**
Project Area	Chico
Program/Project Type	Capacity Program (Normal Overload)
Key Driver of Need	Esquon Bank 1 overload observed in LoadSEER
Known Forecast Uncertainties	Ag pumping
Observed Issues	None
Expected Location of Need	Transformer Bank 1 at Esquon Substation
Expected Magnitude of Need (3-year benchmark, MW)	N/A
Expected Hours of Need (3-year benchmark)	N/A
Load Reduction Requirement Profile Notes	N/A
Wires Solution New/Upgraded Equipment & Location	Replace existing transformer bank at Esquon substation
Wires Solution Associated Load Transfers	None
Expected Equipment In-service Date / Funds Commitment Date	N/A
Base DER Scenario 3-Year Deferral Value per kW of required load reduction deferral ($/kW range)	$ (no deferral value, system-level only)
Very High DER Growth Sensitivity: Magnitude of Need (3-year benchmark, MW)	N/A
Very High DER Growth Sensitivity: Changes to Expected Hours of Need and In-Service Date	N/A
Very High DER Growth Sensitivity: 3-Year Deferral Value per kW of required load reduction deferral ($/kW range)	$ (no deferral value, system-level only)

5.2 Chowchilla

There are nine deferrable projects currently planned in Chowchilla, all of which are either categorized as distribution capacity, voltage support or a combination of the two. There are no deferrable Reliability (Back Tie Capacity) or Resiliency (microgrid) projects in Chowchilla.

A detailed description of each is provided below, along with indicative deferral values under both the base DER growth scenario assumption and the very high DER growth sensitivity.

Table 15: Chowchilla Deferrable Project Summary and Results

Project Name	Le Grand 1104 Reconductor and Voltage Correction-2018	El Nido 1103 Reconductor and Voltage Correction-2018	Chowchilla 1102 Voltage Correction-2018
Project Area	Chowchilla	Chowchilla	Chowchilla
Program/Project Type	Capacity Program (Normal Overload)	Capacity Program (Normal Overload)	Capacity Program (Low Voltage)
Key Driver of Need	Overloaded section of feeder primary line observed in CYME, also causing voltage problems in CYME	Overloaded section of feeder primary line observed in CYME, also causing voltage problems in CYME	Low voltage on feeder primary line observed in CYME
Known Forecast Uncertainties	Ag pumping	Ag pumping	Ag pumping
Observed Issues	None	No SCADA below feeder head, no voltage regulating devices for several miles along feeder	None
Expected Location of Need	Section of overhead primary on feeder 1104 at Le Grand Substation	Section of overhead primary on feeder 1103 at El Nido Substation	Section of overhead primary on feeder 1102 at Chowchilla Substation
Expected Magnitude of Need (3-year benchmark, MW)	6.4	0.85	1.7
Expected Hours of Need (3-year benchmark)	Summer Months, All Hours	Summer Months, All Hours	Summer Months, All Hours
Load Reduction Requirement Profile Notes	Thermal overload profile includes overloads associated with feeder-level minimum trip protection constraint that is mitigated by reconductor downstream. Voltage requirement is larger than and downstream of thermal requirement, hence voltage requirement is reflected here.		
Wires Solution New/Upgraded Equipment & Location	Replace existing overhead conductor section, install new capacitor banks	Replace existing overhead conductor section, install new line voltage regulators and a capacitor bank	Install new line voltage regulators and a capacitor bank
Wires Solution Associated Load Transfers	None	None	none
Expected Equipment In-service Date / Funds Commitment Date	2018	2018	2018
Base DER Scenario 3-Year Deferral Value per kW of required load reduction deferral ($/kW range)	$$$, 100-500 $/kW	$$$$, >500 $/kW	$$, 0-100 $/kW
Very High DER Growth Sensitivity: Magnitude of Need (3-year benchmark, MW)	6	0.65	1.7
Very High DER Growth Sensitivity: Changes to Expected Hours of Need and In-Service Date	No change in hours of need or in-service date	No change in hours of need or in-service date	No change in hours of need or in-service date
Very High DER Growth Sensitivity: 3-Year Deferral Value per kW of required load reduction deferral ($/kW range)	$$$, 100-500 $/kW	$$$$, >500 $/kW	$$, 0-100 $/kW

Project Name	Chowchilla 1103 Voltage Correction-2018	Dairyland 1109 Reconductor-2018	Chowchilla 1104 Reconductor and Voltage Correction-2018
Project Area	Chowchilla	Chowchilla	Chowchilla
Program/Project Type	Capacity Program (Low Voltage)	Capacity Program (New Business Overload)	Capacity Program (New Business Overload)
Key Driver of Need	Low voltage on feeder primary line observed in CYME	Overloaded section of feeder primary line related to new business	Overloaded section of feeder primary line observed in CYME related to new business.
Known Forecast Uncertainties	Ag pumping	New Ag customers and Ag pumping	New Ag customers and Ag pumping
Observed Issues	None	None	None
Expected Location of Need	Section of overhead primary on feeder 1103 at Chowchilla Substation	Section of overhead primary on feeder 1109 at Dairyland Substation	Section of overhead primary on feeder 1104 at Chowchilla substation
Expected Magnitude of Need (3-year benchmark, MW)	0.93	0.88	8.5
Expected Hours of Need (3-year benchmark)	Summer Months, All Hours	Summer Months, All Hours	Summer Months, All Hours
Load Reduction Requirement Profile Notes			Load Reduction Requirement is the sum of voltage and thermal overload requirements because they are electrically separate
Wires Solution New/Upgraded Equipment & Location	Replace existing voltage booster with line voltage regulators	Replace existing overhead conductor section	Replace existing overhead conductor section and install new line voltage regulators
Wires Solution Associated Load Transfers	None	None	None
Expected Equipment In-service Date / Funds Commitment Date	2018	2018	2018
Base DER Scenario 3-Year Deferral Value per kW of required load reduction deferral ($/kW range)	$$, 0-100 $/kW	$$$, 100-500 $/kW	$$, 0-100 $/kW
Very High DER Growth Sensitivity: Magnitude of Need (3-year benchmark, MW)	0.94	0.83	7.63
Very High DER Growth Sensitivity: Changes to Expected Hours of Need and In-Service Date	No change in hours of need or in-service date	No change in hours of need or in-service date	No change in hours of need or in-service date
Very High DER Growth Sensitivity: 3-Year Deferral Value per kW of required load reduction deferral ($/kW range)	$$, 0-100 $/kW	$$$, 100-500 $/kW	$$, 0-100 $/kW

Project Name	El Nido 1104 New Conductor-2019	El Nido Bank 1-2020	Chowchilla 1101 New Conductor-2022
Project Area	Chowchilla	Chowchilla	Chowchilla
Program/Project Type	Capacity Program (Normal Overload)	Capacity Program (Normal Bank Overload)	Capacity Program (Normal Overload)
Key Driver of Need	Overloaded feeder primary observed in LOADSEER	El Nido Bank 1 overload observed in LOADSEER	Overloaded feeder primary observed in LOADSEER for Dairyland 1109 and Dairyland 1113; Overloaded bank observed in LOADSEER for Dairyland Bank 1
Known Forecast Uncertainties	Ag pumping and forecast length at 3 years	Ag pumping and forecast length at 4 years	Ag pumping and forecast length at 6 years
Observed Issues	None	El Nido Bank 1 was already observed to be overloaded in 2015 and 2016.	None
Expected Location of Need	Overhead primary on feeder 1104 at El Nido substation.	Transformer Bank 1 at El Nido Substation	Overhead primary on feeders Dairyland 1113, Dairyland 1109, and transformer bank 1 at Dairyland substation
Expected Magnitude of Need (3-year benchmark, MW)	2.2	3.2	Dairyland 1109: 0.29 Dairyland 1113: 0.68 Dairyland Bk1: 1.8 Combined 1113 + Bk1 = 2.5
Expected Hours of Need (3-year benchmark)	Summer Months, All Hours	Summer Months, All Hours	Dairyland 1109: late summer, morning/early afternoon and late evening Dairyland 1113: late summer, morning and evening Dairyland Bk1: Late summer, All Hours
Load Reduction Requirement Profile Notes			Dairyland 1109 is downstream of Bk 1, while 113 is not. Total need magnitude of 2.5 MW assumes that at least 0.29 MW of 1.8 MW load reduction at Bk1 is on feeder 1109.
Wires Solution New/Upgraded Equipment & Location	Install new overhead conductor section	Install small new overhead conductor section in 2018 and replace existing tranformer in 2020	Install new overhead conductor section
Wires Solution Associated Load Transfers	New conductor enables future load transfers from overloaded Bk 1 (see below).	Load transfers off of Bk 1 enabled by small 2018 new conductor installation and by "El Nido 1104 New Conductor-2019" (above) temporarily mitigate overload prior to new bank in 2020	New conductor enables load transfers from Dairyland 1113 and 1109 circuits, resolving overloads on Dairyland 1109, Dairyland 1113 and Dairyland Bank 1
Expected Equipment In-service Date / Funds Commitment Date	2019	2020	2022
Base DER Scenario 3-Year Deferral Value per kW of required load reduction deferral ($/kW range)	$$$$, >500 $/kW	$$$, 100-500 $/kW	$$$$, >500 $/kW
Very High DER Growth Sensitivity: Magnitude of Need (3-year benchmark, MW)	1.9	2.9	Dairyland 1109: 0.43 Dairyland 1113: 0.74 Dairyland Bk1: 1.1 Combined 1113 + Bk1 = 1.8
Very High DER Growth Sensitivity: Changes to Expected Hours of Need and In-Service Date	No change in hours of need or in-service date	No change in hours of need or in-service date	Dairyland 1109: Hours of need reduced to morning and afternoon, overload pushed out to 2026 Dairyland 1113: No changes Dairyland Bk1: Hours of need unchanged, overload pushed to 2024 Combined: In-service date remains 2022
Very High DER Growth Sensitivity: 3-Year Deferral Value per kW of required load reduction deferral ($/kW range)	$$$$, >500 $/kW	$$$, 100-500 $/kW	$$$$, >500 $/kW

6 Description of Operations and Maintenance Work In Demo B DPAs

As described in Section 2.1, for Demo B PG&E was required to identify the full range of electric services in the selected DPAs, including "upgrades identified in the… maintenance process,"[46] even though, as described in section 3.3, PG&E does not consider those upgrades deferrable in Demo B.

PG&E provides a complete list of 2017 O&M projects currently planned for Chico and Chowchilla in Appendix 4. A summary of the number of 2017 O&M projects in each area is provided below, broken down according to whether the activity is on a distribution line or at a substation in each area:

Table 16: O&M Projects by DPA

Project Category	Chico Number of 2017 projects	Chowchilla Number of 2017 Projects
Distribution Line O&M	468	115
Distribution/Transmission Substation O&M	92	36

These projects primarily consist of routine or scheduled equipment service, tests, inspections as well as repairing or replacing equipment flagged in a prior inspection. Where possible, a location is given for these projects; however, this information is not always provided for distribution line O&M, as these are not always located by circuit.[47]

PG&E chose to provide only 2017 projects because these projects are typically not planned out multiple years in advance, thus providing complete results for the closest forecast year would give a more complete picture the nature of O&M projects in a typical year. Providing the forecasted O&M projects for years beyond 2017 would falsely suggest that those future years have fewer O&M projects than 2017. Finally, given the considerable number of O&M projects, even just for 2017, providing multiple years of forecast would have provided excessive amounts of data without clear benefit in this context.

7 Description of Reliability Work In Demo B DPAs

As described in Section 2.4, for Demo B PG&E was required to identify the full range of electric services in the selected DPAs, including "upgrades identified in the… circuit reliability improvement process."[48] As discussed in Chapter 3, reliability upgrade projects which provide "Reliability (back-tie capacity)" are

[46] ibid, at pp. 28.
[47] If one needs to repair a pole, it is more helpful to have an address or coordinates than it is to know it's on circuit 1101.
[48] ibid, at pp. 28.

considered deferrable in Demo B, while all other reliability upgrades are not considered deferrable in Demo B.

There are no projects currently planned in Chico or Chowchilla which are considered deferrable in Demo B; however, as with O&M projects, these projects are generally not planned out more than 1-2 years; hence, it is possible that a Distribution Reliability (Back Tie Capacity) project could be required in a future year within the 10-year capacity planning horizon. Finally, as with O&M, the specific feeder associated with some types of reliability upgrade are not provided.

The table below summarizes all reliability upgrade projects currently planned in Chico and Chowchilla DPAs:

Table17: Reliability Projects by DPA

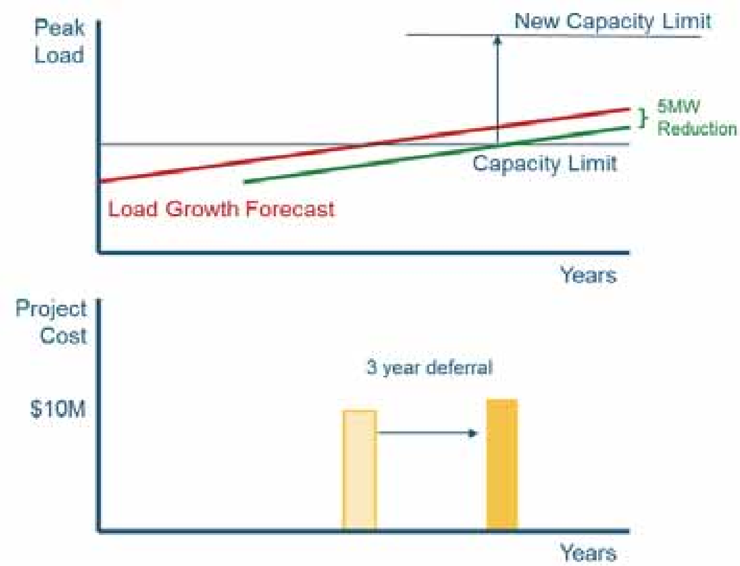
Project Category	**Project Area**	**Description**	**Year**
Distribution Reliability (not back tie capacity)	Chowchilla	Dairyland 1103, Improve reliability by isolating faults	2017
Distribution Reliability (not back tie capacity)	Chowchilla	El Nido 1102, Improve reliability by replacing deteriorated conductor	2017
Distribution Reliability (not back tie capacity)	Chowchilla	Chowchilla 1104, Improve reliability by replacing deteriorated conductor	2018
Distribution Reliability (not back tie capacity)	Chowchilla	Chowchilla 1104, Improve reliability by replacing deteriorated conductor	2018
Distribution Reliability (not back tie capacity)	Chico	Improve reliability by Replace Obsolete UG Switch	2017
Distribution Reliability (not back tie capacity)	Chico	Improve reliability by Replace Obsolete UG Switch	2017
Distribution Reliability (not back tie capacity)	Chico	Improve reliability by Replace Obsolete UG Switch	2017
Distribution Reliability (not back tie capacity)	Chico	Improve reliability by Replace Obsolete UG Switch	2018
Distribution Reliability (not back tie capacity)	Chico	Improve reliability by Replace Obsolete UG Switch	2018
Distribution Reliability (not back tie capacity)	Chico	Improve reliability by Replace Obsolete UG Switch	2018
Distribution Reliability (not back tie capacity)	Chico	Improve reliability by Replace Obsolete UG Switch	2018
Distribution Reliability (not back tie capacity)	Chico	Improve reliability by Replace Obsolete UG Switch	2018
Distribution Reliability (not back tie capacity)	Chico	Improve reliability by Replace Obsolete OH Switches	2017

8 LNBA Calculations in Demo B: T&D Project Deferral Benefit

8.1 Deferral Benefit Calculation Overview

In Demo B, DERs are considered able to defer distribution upgrades by reducing load such that they mitigate the problem that is the driving need or needs for a distribution upgrade. The diagram below provides an example of the simple case of a forecasted overload on a distribution facility which would typically require a distribution capacity upgrade.

Figure 4: Deferral Schematic (Curtesy E3)



The upper chart depicts a DER's ability to delay, for three years, a forecasted overload by reducing peak load by 5 MW. The lower chart depicts the effect of this delay on the timing and quantity of capital investment for the distribution capacity upgrade project which mitigates the overload. Note that the project cost is nominally larger after the three year deferral due to inflation of material and labor.

The utility customer benefit of a deferral is primarily a result of the cost to capitalize such an investment: the present value of raising capital in year 4 instead of year 1. The quantity of this benefit is calculated in Demo B using the Real Economic Carrying Charge (RECC) method, per commission direction.[49] In this method, a RECC Factor is multiplied by the original upgrade project capital cost to yield the benefit of a one year deferral. This factor, expressed below, is a function of the utility's cost of capital and the life of the capital asset as well as inflation.

RECC Factor:[50]

$$\text{RECC} = \frac{(r-i)}{(1+r)}\left(\frac{(1+r)^N}{(1+r)^N-(1+i)^N}\right)$$

[49] ibid, p. 30, "Compute a total avoided cost…. Use the Real Economic Carrying Charge method"

[50] This is calculated in the LNBA Tool, Project Inputs & Avoided Costs tab, Row 110.

i=inflation, r=discount rate, N = life of the capital asset

The RECC Factor multiplied by original capital investment does not fully capture all of the savings from a deferral. This is because the actual amount recovered from ratepayers for the original capital investment is always greater than the project cost. The revenue requirement or RRQ recovered from utility customers includes various other costs such as taxes, franchise fees, utility authorized rate of return, and overheads. These general cost factors are captured in a RRQ Multiplier, which is applied to the product of capital investment and RECC factor. The RRQ Multiplier may vary for different projects, for example, where different types of equipment are treated differently in tax accounting.

Finally, utility customers also avoid any annual O&M activities associated with a new distribution facility as well. Since this is an expense passed to customers as is, it is not multiplied by the RECC factor or the RRQ Multiplier. Since O&M costs are incurred in the year they are performed lifetime O&M is also subject to inflation. This factor only applies to new equipment, as a replacement piece of equipment would likely require a similar amount of O&M expense as the prior equipment of the same type.

The complete expression of rate reduction associated with a one-year deferral is thus

Deferral Benefit = [original project cost] x [RECC Factor] x [RRQ Multiplier] + [levelized annual O&M]

For a multiple-year deferral, the -yearly deferral value beyond the first year are simply discounted to a present value using a discount factor derived from same discount and inflation rates used in the RECC factor.[51]

8.2 LNBA Tool Deferral Benefit Calculation Inputs and Outputs

This section provides an overview of the primary LNBA Tool inputs, outputs and settings related to the T&D project deferral benefit calculation. Additional description of these inputs, outputs and settings as well as others are provided in Appendix 2.

8.2.1 Deferrable Project Inputs

Major inputs related to the deferrable project are summarized below. These are categorized as either Universal Inputs analysis or Project Specific Inputs.

The table below summarizes the universal inputs, which are primarily financial constants required to calculate a deferral value

Table 18: Deferrable Project Inputs: Universal Inputs

Name	Location in LNBA Tool	Description	PG&E Source
Discount Rate	Project Inputs & Avoided Costs; C5	Used for various financial calculations.	Derived from PG&E's Weighted Average Cost of Capital (WACC) as described

[51] This total deferral benefit is calculated in the LNBA Tool, Project Inputs & Avoided Costs tab, Rows 145-154

			below
RRQ Multiplier	Settings; C13:E28	Converts capital cost to revenue requirement.	These are derived as described below
Equipment Inflation Rate	Settings; F13H28	These are set at a standard 2.5%	Standard Assumption
O&M Inflation Rate	Settings; I13:K28	These are set at a standard 2.5%	Standard Assumption
Book Life	Settings; L13:L28	Used to calculate the RECC Factor	These are obtained from a recent PG&E financial filings to the CPUC
O&M Factor	Settings, M13:O28	Used to determine annual O&M savings for associated with deferring the installation of new distribution equipment. These are expressed as annual O&M as a percent of capital cost.	This is obtained from PG&E's Rule 2 tariff.[52]

Derivation of Discount Rate

PG&E used a 7% discount rate for financial calculations in Demo B. This is derived from PG&E's most recently CPUC-approved [53] return on rate base of 8.06% as follows:

PG&E'S capital structure, as approved by the CPUC, comprises 52.00% common equity, 47.00% long-term debt, and 1.00% preferred stock. It is authorized to earn a return of 10.4% on common equity, and recover 5.52% and 5.6% for long-term debt and preferred stock respectively. The given capital structure and respective costs result in a return on rate base of 8.06%[54].

PG&E's discount rate for utility project revenue requirements is its weighted-average cost of capital (WACC), which reflects the tax deductibility of interest expense. Using an aggregate tax rate of 40.75% (that includes 35% federal tax and 8.84% state tax), PG&E's weighted average post-tax cost of long-term debt stands at 1.54%[55]. Combined with the weighted average cost of common equity and preferred stock (from above), PG&E's overall WACC stands at 7%, which is used for discounting all future cash flows considered to have the same risk as PG&E's overall business risk.

[52] This is the monthly cost-of-ownership charge for special distribution facilities financed by the customer: 0.6% multiplied by 12 to yield an annual percentage of 7.2%. PG&E's Rule 2 is available here: http://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_2.pdf

[53] CPUC Decision D12-12-034 set the currently applicable WACCs for each IOU. Available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M040/K655/40655308.PDF

[54] (52%*10.4%+47%*5.52%+1%*5.6%)

[55] [47%*5.52%*(1-0.4075)]

Derivation of RRQ Multipliers

PG&E used the following Revenue Requirement (RRQ) Multipliers at a 7% discount rate:

- Overhead Conductors & Devices: 151%
- Transformers: 145%

The RRQ Multipliers above are derived as follows:

PG&E uses a simplified Results of Operations (RO) Model called CHARGE that calculates revenue requirements for a capital investment subject to cost-of-service ratemaking. Total revenue requirement for a utility asset (electric distribution asset in the LNBA context here) is defined as the sum of book depreciation, income taxes, return on rate base, property taxes, and insurance costs.

The CHARGE model uses asset-specific book life and salvage value to calculate annual book depreciation. Then, it uses the annual book depreciation along with asset-specific tax data, to calculate annual asset rate base. With authorized cost of capital data, CHARGE subsequently calculates the required annual return on that rate base. In addition, CHARGE also calculates property taxes based on annual net plant balance, and the asset's annual insurance cost based on gross book value.

As stated above, the summation of all these variables (i.e. book depreciation, income taxes, return on rate base, property taxes, and insurance costs) results in asset-specific annual revenue requirement. The annual revenue requirement is finally discounted back to present value (using asset-specific book life) to calculate an overall RRQ multiplier for the respective asset. One can, thus, note that RRQ multipliers for OH Conductors & Devices and Transformers (as given above) differ primarily because they have different book lives and net salvage values.

Table 19: Deferrable Project Inputs: Project-Specific Inputs

Name	Location in LNBA Tool	Description	**PG&E Source**
Project Identifiers	Project Inputs & Avoided Costs; Rows 18 and 19	Used to identify each project.	NA
Equipment Type	Project Inputs & Avoided Costs; Row 20	Used to select RRQ Multiplier, Book Life, and O&M Factor for a project	NA
Project Cost	Project Inputs & Avoided Costs; Row 27	Used to calculate deferral benefit. The tool evaluates low and high sensitivities, reflecting uncertainty in the cost estimate. These are derived from cost estimating standards.[56]	PG&E's project costs were based on existing, publicly-available PG&E-specific unit cost information as well as costs provided in PG&E's

[56] Specifically, the low (x0.7) and high (x1.5) sensitivities reflect a Class 4 estimate as described in the American Association of Cost Estimating recommended practice 17R-97, available at: http://www.aacei.org/toc/toc_17R-97.pdf

			2017 GRC
Project Install/ Commitment Year	Project Inputs & Avoided Costs; Row 30	Compared with DER Install Year to check whether a project can be deferred by a DER; also used to evaluate duration of a deferral.	PG&E Distribution Planning Engineers
Project Flow Factors	Project Inputs & Avoided Costs; Table at C48	Used to identify upstream projects and the extent to which they're impacted by load reduction at downstream project locations	PG&E used 100%, where one project is downstream of another, and 0% otherwise
Loss Factors	Project Inputs & Avoided Costs; Table at C61	Used to translate Hourly DER Profile to an actual impact on loading at the location of the problem that causes a deferrable project to exist. [NOTE, these are separate from loss assumptions embedded in avoided energy cost described in Section 9.3]	PG&E used a 1.063 line loss factor from public sources, representing losses between the substation and distribution secondary line.[57]
Load Profile/Need Profile	AreaPeaks; tables at rows 16-8775	Used to define profile of required DER load reduction to achieve deferral.	PG&E Distribution Planning Engineers provided the load reduction need profile for each deferrable project
Threshold	AreaPeaks; Row 13	Defines the threshold above which an overload is assumed to occur in the Load Profile/Need Profile. The hours and magnitude of overload are used to validate whether or not a DER defers a project by mitigating the problem that causes the deferrable project to exist.	Since the hourly profile PG&E used is a "Need" profile rather than a load profile, PG&E set this input to zero.

[57] A Recent CEC report summarized line loss factors used by the CA IOUs across planning activities. 1.063 is the difference between the cumulative line loss factors for "secondary" (1.101) and "transmission" (1.038) in Table 6. For DERs connected at the distribution primary, this would be the difference between the cumulative line loss factors for "Primary" (1.08) and "Transmission" (1.038) or 1.021. The report is available at: http://www.energy.ca.gov/2011publications/CEC-200-2011-009/CEC-200-2011-009.pdf. A more detailed analysis of specific line voltages and lengths between the DER solution and the location where load reduction is needed for a deferral would provide more accurate results.

8.2.2 DER Inputs

Major inputs related to the DER solution are summarized below. These are the primary inputs that DER providers or stakeholders would use to evaluate various DER alternatives.

Table 20: DER Inputs

Name	Location in LNBA Tool	Description	Source
DER Location	DER Dashboard, F4	Used to identify the primary deferrable project which the DER is downstream from.	User Input
DER Useful Life	DER Dashboard, F6	Used to calculate lifecycle avoided costs.	User Input
DER Install Year	DER Dashboard, F7	Used to determine which projects are deferrable and for various avoided cost analyses.	User Input
Defer T&D to this year	DER Dashboard, F8	Used to identify the DER load reduction requirement associated with the deferrable projects upstream of DER Location. If set to 2025, for example, the tool checks whether the Hourly DER Profile is sufficient to mitigate the problem causing upstream deferrable projects to exist in 2024 and prior years.	User Input
Hourly DER Profile	DER Dashboard, F57:F8816	Hourly load increase/decrease associated with a DER solution. Should be constructed using 2015 calendar and a 1:10 weather year. DER portfolios must be aggregated to a single, aggregate profile.	User Input
Dependability in local Area	DER Dashboard, F5	Use this to easily scale the DER profile up or down.	User Input

8.2.3 Tool Settings

In addition to inputs, the LNBA Tool has a variety of settings that will determine how certain calculations are made. Major settings and default values are described below

Table 21: Deferral Calculation Tool Settings

Name	Location in LNBA Tool	Description	PG&E Default
T&D Value Basis	DER Dashboard, E13	“Allocation-based Average” vs “Requirement-Based Threshold”. "Allocation-Based " assigns partial deferral value even if the peak reduction is insufficient for	Requirement-based threshold

		deferral, while "Requirement-Based" the DER hourly profile must meet or exceed the deferral requirement in all hours to be assigned any T&D deferral value	
Case to use for allocated hourly costs	Project Inputs and Avoided Costs, C8	Select whether to use the base cost or the high or low sensitivities.	Base
Include or Exclude Deferral Value	DER Dashboard, I24:I33	Manually include or exclude T&D deferral value associated with deferrable projects upstream of DER Location. Default: Include	Include

8.2.4 Outputs

The primary LNBA Tool output is lifecycle DER avoided cost, which is provided in total as well as broken down by component in the table in the DER Dashboard tab at cell F39. This includes the T&D deferral benefit component, which is provided explicitly at cell H49.

8.3 Transmission Deferral Benefit Calculation

The tool is capable of evaluating a transmission project deferral opportunity in the same way that distribution projects are evaluated in Demo B. The same inputs are required, primarily the timing and cost of a deferrable project and the DER load reduction profile required to achieve that deferral.

The May, 2 ACR specifically directs the utilities to evaluate the transmission component of LNBA by quantifying the co-benefit value of ensuring that preferred resources relied upon to meet planning requirements in the California ISO's approved 2015-2016 Transmission Plan[58] materialize as assumed. However, the 2015-2016 Transmission Plan does not provide sufficient information to do this analysis. Specifically, it does not identify projects which would be required in the absence of those preferred resources or the associated project costs. It also does not provide information needed to develop DER load reduction requirements.

In lieu of analyzing specific transmission deferral benefits, the LNBA Tool includes a generic system-wide transmission benefit input for users to define.[59] Note that this input is per kW of the DER type that is being analyzed (e.g. per kW of PV). The default transmission value is set to zero, consistent with the default value found in the Public Tool developed in the NEM Successor Tariff Proceeding (R.14-07-002).

The IOUs anticipate a significant amount of effort to refine this simplified approach in the future, enabling a more detailed treatment of transmission benefits similar to the detailed analysis of distribution benefits in Demo B.

[58] This plan is available on the CAISO Website at: http://www.caiso.com/Documents/Board-Approved2015-2016TransmissionPlan.pdf
[59] Located in the LNBA Tool's DER Dashboard tab at cell K6

9 LNBA Calculations in Demo B: Other LNBA Components

As indicated in the Section 2.2.1, the system-level avoided cost module calculates the benefits of system wide components. These components include avoided energy, avoided generation capacity, avoided GHG, avoided RPS, avoided ancillary services, renewable integration cost adder, and societal and public safety. The LNBA tool provides generic estimates of these benefits based on public information, which doesn't reflect PG&E's confidential evaluation of these benefits.

9.1 Sources

The avoided cost calculator version 1.0[60] [61], a revised distributed energy resources avoided cost model ("DERAC"), was used to derive avoided energy, system avoided generation capacity, avoided GHG, avoided RPS, and avoided ancillary services. For each component sourced from the avoided cost calculator, an hourly profile is provided for 31 years (2016-2047) in the 'SystemAC' tab of the LNBA tool.

The source for the renewable integration cost adder is the interim value adopted in 2014 from D.14-11-042.[62]

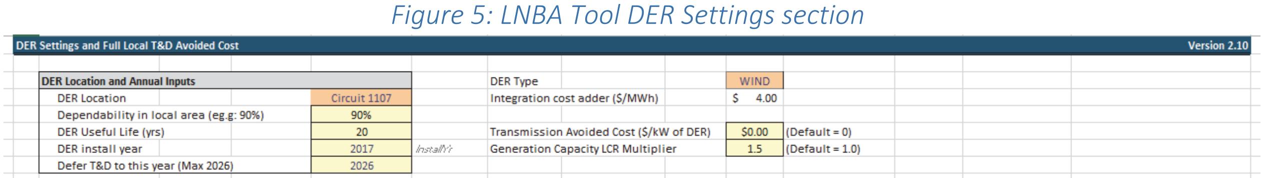
9.2 User Inputs in 'DER Dashboard' Tab of LNBA Tool

In order for the system-level avoided cost module to properly calculate the value of the components, the user needs to provide basic DER information, benefits that the DER can obtain, and a DER hourly profile. A user will need to input these pieces of information in the 'DER Dashboard' tab of the LNBA tool. These inputs will need to be defined in three sections of the 'DER Dashboard' tab: 'DER Settings and Full Local T&D Avoided Cost', 'DER Avoided Costs', 'DER Hourly Shape and Calculations'.

9.2.1 'DER Settings and Full Local T&D Avoided Cost' Section

In the 'DER Settings and Full Local T&D Avoided Cost' section (Row 1) of the 'DER Dashboard' tab, the user will need to select the DER location and DER type. In addition, the user will need to define the, DER useful life, DER install year, and local RA multiplier. Additional inputs in this section - last year of deferral, dependability in the local area, and transmission avoided cost – relate only to T&D calculations as described in Chapter 8. See the figure below for an example of the 'DER Settings and Full Local T&D Avoided Cost' section.

Figure 5: LNBA Tool DER Settings section



9.2.2 'DER Impact on Local T&D' Section

In the 'DER Impact on Local T&D' section (Row 11), the user selects the T&D value basis and the components to include in the calculation as described earlier in section 8.2.3.

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60 Avoided Cost Calculator v1

61 The use of the avoided cost calculator as the source for avoided energy, system capacity, GHG, RPS, and ancillary services costs provides an estimation of those components based on publicly available data.

62 *Decision Conditionally Accepting 2014 Renewables Portfolio Standard Procurement Plans and an Off-Year Supplement to 2013 Integrated Resource Plan*, November, 24, 2014, pp. 61-63.

9.2.3 'DER Avoided Costs' Section

The 'DER Avoided Cost' section (Row 37) contains two areas. In the 'Include Component?' area, the user can select whether or not the DER solution will receive the benefit of each LNBA component. Under the 'Lifecycle Value from DER by Component ($)' area, the 'DER Avoided Costs' section provides outputs of total value ($) of the DER solution by component for the contracted life. The figure below shows an example of the 'DER Avoided Costs' section.

Figure 6: DER Avoided Costs Section

DER Avoided Costs

Include Component?	
Energy	TRUE
Gen Capacity	TRUE
Ancillary Services	TRUE
CO2	TRUE
RPS	TRUE
Flex RA	TRUE
Integration Cost	TRUE
System Trans	TRUE
T&D	TRUE

Lifecycle Value from DER by Component ($)	Circuit 1107	All Affected Areas
Energy	$1,982,819	$1,982,819
Gen Capacity	$555,478	$555,478
Ancillary Services	$18,393	$18,393
CO2	$797,824	$797,824
RPS	$808,743	$808,743
Flex RA	-$306,118	-$306,118
Integration Cost	-$221,372	-$221,372
System Transmission	$0	$0
Local T&D	**$0**	**$1,956,858**
Total Avoided Cost ($)	**$3,635,767**	**$5,592,625**

9.2.4 DER Hourly Shape and Calculations Section

In the 'DER Hourly Shape and Calculations' section (Row 52), the user will need to input a DER hourly shape for the entire year. The hourly shape is entered in the yellow highlighted cells. This is the single input upon which all system-level avoided costs are based. In general, positive hourly values will result in a positive system-level benefit while negative hourly values, for example representing storage charging at certain times, will result in a cost (negative benefit).

In the 'Hourly lifecycle unit avoided costs (hourly $/kW)' area, the tool provides the hourly net present value by component for the contracted life of the DER solution. This output with the hourly DER solution provides the information needed to calculate the total value by component in the 'DER Avoided Costs' section.

Figure 7: DER Hourly Shape and Calculations

DER Hourly Shape and Calculations

User Input for DER Hourly Shape				Hourly lifecycle unit avoided costs (hourly $/kW). Adjusted for exclusions and losses, but not for dependability or generation multiplier							
PST Hour Starting	Month	Hour	DER at meter (kW)	Lifecycle Energy	Lifecycle Gen Cpcty	Lifecycle AS	Lifecycle CO2	Lifecycle RPS	Lifecycle Flex RA	Local T&D for Circuit 1107	Local T&D for All Included Affected Areas
1/1/15 12:00 AM	1	0	0.00	$0.58	$0.00	$0.01	$0.18	$0.17	$0.00	$0.00	$0.01
1/1/15 1:00 AM	1	1	0.00	$0.54	$0.00	$0.00	$0.17	$0.17	$0.00	$0.00	$0.01
1/1/15 2:00 AM	1	2	0.00	$0.53	$0.00	$0.00	$0.17	$0.17	$0.00	$0.00	$0.01
1/1/15 3:00 AM	1	3	0.00	$0.52	$0.00	$0.00	$0.17	$0.17	$0.00	$0.00	$0.01
1/1/15 4:00 AM	1	4	0.00	$0.54	$0.00	$0.00	$0.17	$0.17	$0.00	$0.00	$0.01
1/1/15 5:00 AM	1	5	0.00	$0.59	$0.00	$0.01	$0.18	$0.17	$0.00	$0.00	$0.01
1/1/15 6:00 AM	1	6	0.00	$0.54	$0.00	$0.00	$0.17	$0.17	$0.00	$0.00	$0.01
1/1/15 7:00 AM	1	7	0.00	$0.53	$0.00	$0.00	$0.17	$0.17	$0.00	$0.00	$0.01
1/1/15 8:00 AM	1	8	105.30	$0.52	$0.00	$0.00	$0.17	$0.17	$0.00	$0.00	$0.01
1/1/15 9:00 AM	1	9	720.21	$0.48	$0.00	$0.00	$0.17	$0.17	$0.00	$0.00	$0.01
1/1/15 10:00 AM	1	10	154.16	$0.45	$0.00	$0.00	$0.17	$0.17	$0.00	$0.00	$0.01
1/1/15 11:00 AM	1	11	293.76	$0.43	$0.00	$0.00	$0.17	$0.17	$0.00	$0.00	$0.01
1/1/15 12:00 PM	1	12	315.30	$0.41	$0.00	$0.00	$0.17	$0.17	$0.00	$0.00	$0.01
1/1/15 1:00 PM	1	13	175.15	$0.37	$0.00	$0.00	$0.17	$0.17	$0.00	$0.00	$0.01
1/1/15 2:00 PM	1	14	940.02	$0.40	$0.00	$0.00	$0.17	$0.17	$0.00	$0.00	$0.02
1/1/15 3:00 PM	1	15	727.53	$0.47	$0.00	$0.00	$0.17	$0.17	$0.00	$0.00	$0.02
1/1/15 4:00 PM	1	16	174.38	$0.70	$0.00	$0.01	$0.21	$0.17	$0.00	$0.00	$0.02
1/1/15 5:00 PM	1	17	0.00	$0.87	$0.00	$0.01	$0.26	$0.17	$0.00	$0.00	$0.01
1/1/15 6:00 PM	1	18	0.00	$0.89	$0.00	$0.01	$0.27	$0.17	$0.00	$0.00	$0.01
1/1/15 7:00 PM	1	19	0.00	$0.80	$0.00	$0.01	$0.24	$0.17	$0.00	$0.00	$0.01
1/1/15 8:00 PM	1	20	0.00	$0.81	$0.00	$0.01	$0.25	$0.17	$0.00	$0.00	$0.01
1/1/15 9:00 PM	1	21	0.00	$0.71	$0.00	$0.01	$0.21	$0.17	$0.00	$0.00	$0.01
1/1/15 10:00 PM	1	22	0.00	$0.66	$0.00	$0.01	$0.20	$0.17	$0.00	$0.00	$0.01
1/1/15 11:00 PM	1	23	0.00	$0.58	$0.00	$0.01	$0.18	$0.17	$0.00	$0.00	$0.01

Overview | DER Dashboard | Project Inputs & Avoided Costs | AreaPeaks | ReMapping | SystemAC | Flex RA | Settings | ...

9.3 LNBA Tool Avoided Energy and Losses

The avoided cost of energy is defined as the total net present value of energy that does not need to be procured at the system level due to the generation or savings of the DER solution. Of note, the impact of transmission and distribution line losses have already been factored into the avoided cost values. Thus, there is no need for a line loss factor when calculating the system wide avoided cost values by component. In order to get the value of this offset energy, the time, length, and amount of the energy of the DER solution needs to be known. For example, if the DER solution provides one MWh of energy on January 1st, 2016 at 8 AM for one hour, the corresponding energy price for that time is $27.59/MWh. The value of this avoided energy is:

$$1\ MWh * \$27.59/MWh = \$27.59$$

9.3.1 Conservation Voltage Reduction

The benefit of conservation voltage reduction, like any efficiency measure, is the value of the saved energy and other associated system-level benefits. As described in section 3.2.2, CVR load reduction can be easily incorporated into the hourly DER profile, upon which the LNBA system-level benefits are based.

9.4 LNBA Tool Avoided Generation Capacity

The avoided cost of generation capacity is subdivided into three different types: system, local, and flexible capacity.

Avoided system generation capacity cost is defined as the total net present value of generation capacity that does not need to be procured at the system level, due to the reduction in system peak load due to the DER solution. In order to calculate the value of the system generation capacity, the time, length, and amount of the capacity of the DER solution need to be known. For example, if the DER solution provides one MW of capacity on June 30th, 2016 at 3 PM for one hour, the corresponding system capacity for that time is $0.0277/MWh. The value of this avoided system capacity is:

$$1\ MW * 1\ h * \$0.0277/MWh = \$0.03$$

For local generation capacity, the IOUs were directed to use DERAC values;[63] however, DERAC does not include local generation capacity prices needed to evaluate benefits associated with avoided local RA purchases. The LNBA Tool includes a generic “Generation Capacity LCR Multiplier” so that a user can apply a local capacity premium to the DERAC system generation capacity prices included in the LNBA Tool as appropriate.[64] This value is defaulted to 1.

The avoided cost for flexible capacity is defined as the value of flexible capacity that does not need to be procured from the offsetting flexible capacity provided by the DER solution. In the LNBA tool, the value of flexible capacity was assumed to be $20 / kW-yr in 2016. For future years, the $20 / kW-yr value was escalated by 5% each year. To calculate the value of the avoided flexible capacity for a specific DER solution, the DER solution hourly profile is assessed for its impact on the annual maximum three-hour ramp, upon which the flexible RA requirements are based.

9.5 LNBA Tool Avoided GHG, AS, and RPS

Avoided GHG, RPS, and ancillary services costs are defined as the total net present values of each component that does not need to be procured at the system level (due to the DER providing the corresponding offset to each component). Each hourly amount of DER load increase or decrease in the hourly DER profile is multiplied by an hourly GHG, AS, and RPS avoided (or increased) cost.

The hourly GHG avoided cost is based on assumptions in the DERAC about the emission rate of the marginal generator in each hour. The DERAC AS hourly avoided cost is based on recent CAISO market price data. The LNBA Tool does not account for any GHG emissions resulting from a DER solution or AS services directly provided by a DER solution.

For avoided RPS, the LNBA tool assumes DER solutions are behind-the-meter and can therefore offset the need to procure RPS energy due to reduced energy sales. The hourly RPS avoided cost accounts for hours of RPS curtailment that are forecasted in the DERAC tool in future years, during which time there is a negative RPS avoided cost for load reductions. The LNBA tool does not account for any RPS-eligible Renewable Energy Credits (RECs) that a DER solution may generate.

Parallel to calculations of avoided energy and system capacity costs, the values of avoided GHG, RPS, and ancillary services are calculated by summing the net present values (using the hourly DER values) and multiplying the corresponding hourly value for each component on a per MWh basis.

9.6 LNBA Renewable Integration Cost

The renewable integration cost is dependent on the solution technology. Consistent with D.14-11-042, for solar sources, the renewable integration cost is $3 / MWh. For wind sources, the renewable integration cost is $4 / MWh. All other technologies are $0 / MWh. To calculate total renewable integration cost, the appropriate DER technology is selected. The $ / MWh cost is subsequently multiplied by the total energy produced by the DER solution for its contracted life.

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[63] ACR, table 2, Approved LNBA Methodology Requirements Matrix for Demonstration Project B at p. 25, “Avoided Generation Capacity, System and Local RA, Use DERAC values”

[64] Located in the LNBA Tool DER Dashboard tab at cell K7

9.7 Other LNBA Components Not Calculated in LNBA Tool: Societal and Public Safety Benefits

Societal benefits are broadly defined as any benefits (or costs), including those related to public safety, that are linked to the deployment of DERs which are external to the IOUs' revenue requirements (i.e. do not have a nexus to rates).

Many environmental impacts associated with energy production have been internalized in the IOU revenue requirements through policy mechanisms such as the RPS and multi-sector GHG Cap and Trade system. Many public safety impacts associated with energy production have been internalized in the IOU revenue requirement through other regulatory mechanisms, such as mandatory inspection and maintenance programs.

There are several regulatory activities focused on societal benefits currently under-way: Energy Division is currently developing a proposal to address how societal benefits may be included in DER cost effectiveness analysis[65] in the IDER proceeding; the Commission is leading an Integrated Resource Plan proceeding, a long-term electric resource planning proceeding initiated by SB350 (2015) which incorporates statewide GHG emission reduction goals and also includes cost of air pollutants or GHG emissions local to disadvantaged communities, per statute.

These activities necessarily overlap and require close coordination; however, it is expected that information regarding specific types of societal benefits and quantification approaches will be determined in one or both of these proceedings. Such information could be used to inform future definitions or quantification of societal benefits in LNBA.

For Demo B, no societal or public safety components were quantified. Long term improvements to the LNBA methodology and tool may quantify societal and/or public safety components.

9.8 Other LNBA Components: Example Calculation and Results

For illustration, a set of system-level avoided cost results is provided for a generic DER which generates 100 kW in all hours and has a 10-year life:

Table 22: Example System-Level Benefits Calculation

Lifecycle Value from DER by Component ($)	
Energy	$250,874
Gen Capacity	$105,663
Ancillary Services	$2,232
CO2	$84,511
RPS	$107,105
Flex RA	$0
Integration Cost	$0
System Transmission	$0
Total System Level Avoided Cost	$550,384

[65] Materials from a 9/22/2016 workshop on this topic are available online at: http://www.cpuc.ca.gov/General.aspx?id=10745

10 Conclusions and Caveats

PG&E, in coordination with the other CA IOUs and the LNBA WG, has sought to fulfill the Commission's guidance and requirements for this demonstration of LNBA in a small portion of PG&E's distribution territory.

Consistent with the vision of the DRP, PG&E expects that LNBA will ultimately provide useful information for determining optimal DER locations and employing market mechanisms to deploy DERs in those locations.

PG&E expects LNBA methodology refinement to be an ongoing process; specific refinements, lessons learned and caveats are briefly discussed below.

10.1 Refinements

A variety of refinements to the DER scenario development and allocation approaches used in Demo B are envisioned, including many that were noted in PG&E's DRP Filing:[66]

- Better validation of long-term forecasts at a granular level, including consideration of limiting factors at high penetrations
- Managing uncertainty inherent in modeling consumer behavior
- Capturing uncertainty in future policy developments
- Developing robust methods with limited sample sizes, especially at more granular levels
- Capturing Demand Response effects on distribution peaks, for example, capturing separately non-event based DR programs such as rate-based programs
- Improving DER shape profiles, such as developing up-to-date EE profiles by end use or customer type[67] and using location-specific DG profiles where locational differences are significant.

Additional refinements relate to several inputs to the deferral value calculation:

- Develop device-specific O&M factors to more precisely capture avoided O&M associated with deferring a new piece of equipment

10.2 Lessons Learned

- Understanding uncertainty in planning for a dynamic distribution system is critical to ensuring that deferral benefit estimates are realistic and realized. As observed in the Chico DPA, forecasts and resulting investment plans change.
- PG&E and the other CA IOUs spent a considerable amount of time considering how transmission deferral opportunities could be incorporated in Demo B. The analysis required for the transmission network is far more complex than for a typical distribution deferral opportunity and must ultimately be incorporated into the CAISO transmission planning process.

[66] PG&E DRP filing at p. 108.
[67] CEC is pursuing, through an EPIC project, data that would enable load shape integration at the end use level (RFP-15-301, "Market Analysis of Trends in California Investor-Owned Utility Electricity Load Shapes")

- PG&E and the other CA IOUs sought, in Demo B, to provide technology-agnostic requirements by translating all DER deferral requirements into a required load reduction profile. This ensures, for example, that an EE solution is able to mitigate a voltage support project. For some voltage support projects; however, this resulted in very high load reduction requirements. It may be that these services could be provided more easily through reactive power management.
- The impact of the Very High DER growth scenario on distribution projects and their deferral requirements (i.e. magnitude, hours and in-service date) is not necessarily consistent or intuitive. In some cases impact was minimal, in others substantial, while in several cases the magnitude of load reduction requirement actually increased.

10.3 Caveats

PG&E offers several caveats related to Demo B and more broadly to the use of DERs to defer grid investments below.

Caveats related to Demo B

- No market sensitive or confidential information is provided in this report or associated datasets made available
- Nothing in this demonstration project should be interpreted as a commercial request for offers
- Demo B Deferral values are estimated ranges based on current conditions and publicly available PG&E unit cost information rather than detailed project estimates
- DERAC avoided costs used to estimate system-level benefits are generated by E3 and should not be considered PG&E estimates of market value for any resource
- PG&E does not evaluate or make assumptions about specific DER solutions or evaluate the effectiveness or reliability of any technologies or non-wires solutions in Demo B

Caveats related to the use of DERs to defer grid investments

- PG&E recognizes the ability of DERs to defer traditional infrastructure investment; however, valuing that ability should capture risks due to uncertainties embedded in planning for a dynamic distribution system:
    - Load growth above expectation may require capital investment to avoid potential reliability issues, despite DER deployment
    - Load growth below expectation may eliminate a capital investment driver, regardless of DER deployment
- PG&E has made and continues to make substantial improvements to its load forecasting approaches, including highly granular forecasting of both load and DERs; however some uncertainty in forecasting is unavoidable[68]
- Capturing uncertainty risk is critical to ensuring that the ultimate objective of reducing cost to PG&E customers is achieved

[68] For example, see a recent analysis of uncertainty in forecasting here:
http://www.nytimes.com/2016/11/16/upshot/presidential-forecast-postmortem.html

11 Appendix 1: Heat Map Location and Description

PG&E's combined Demo A and Demo B heat map is not publicly available at the time this report is to be served. A link to PG&E's Combined Demo A and Demo B heat map will be served separately.

11.1 Heat Map Indicative Deferral Values

These are described and presented in Chapter 5. A machine-readable version of the Chapter 5 results tables, which are reflected geospatially in the heat map, will be made available as a downloadable file accessible via PG&E's combined Demo A and Demo B heat map.

11.2 Heat Map DER Growth Scenario Data

Cumulative annual DER impacts on peak load for each feeder are included in the heat map and downloadable DER Impact dataset. The heat map presents only the combined impact of all DER types for a single year in each planning horizon: 2018 DER impacts are shown for the short-term horizon; 2020 DER impacts for the medium-term horizon, and 2022 DER impacts for the long-term horizon. In contrast, the downloadable dataset provides disaggregated impacts for all years. In either case, these data reflect only DER impacts in the hour that each feeder peaks before accounting for DERs' impact on when that peak occurs (i.e. the gross load peak hour).

The DER coincident peak contribution is the effect that DERs have to raise or lower the observed peak of each bank and feeder. Typically these expected peaks will vary depending on the customer make-up of each circuit. Residential customers typically consume the most power during evening hours, while both commercial and industrial customers typically peak at noon during business hours. In order to serve all customers, PG&E must anticipate each circuit peak to determine the DER contribution before committing to system upgrades. This can be done by plotting the circuit power consumption based on a "Month-Hour" to approximate the typical consumption on say a typical September day at 4pm. We call this the "Shape profile", which can be attributed to both load and DER types. An example Load Shape can be seen below:

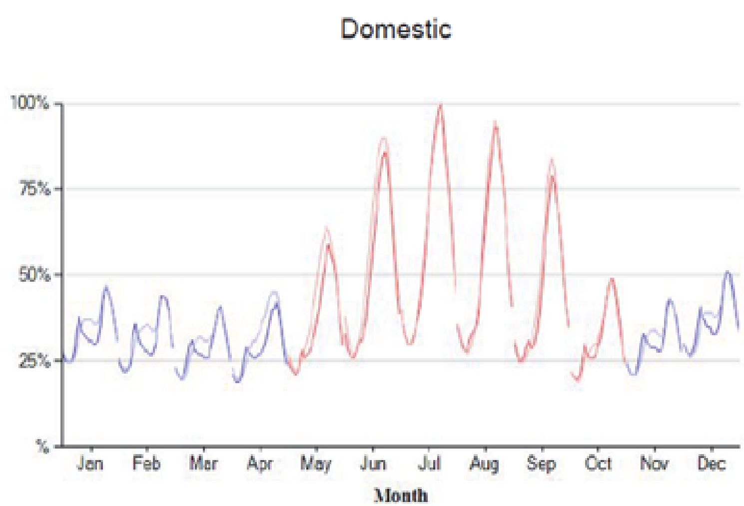

Figure 1: Residential customer load shape

PG&E contracts with a third party software provider, Integral Analytics (IA) to develop the tools necessary to make Distribution Planning forecasts and shape profiles. IA use statistical models to develop different customer load types, DER types, and assist in making distribution planning assumptions such as weather, local economies, etc. Since these assumptions are highly variable in reality, IA has developed percentile shape profiles that plots the range of power consumption for each Month-Hour. An example of a high percentile load scenario would be a residential area experiencing an unexpected heat wave, causing higher AC loads during the hottest hours. This scenario would represent the 95th percentile of an area's load shape, as opposed to a mild day which could rank within the 5 – 50% percentile. Typically higher percentiles result in more exaggerated peaks to account for local sensitivities. The graph below shows an example of the possible power consumption range at various Month-Hours.

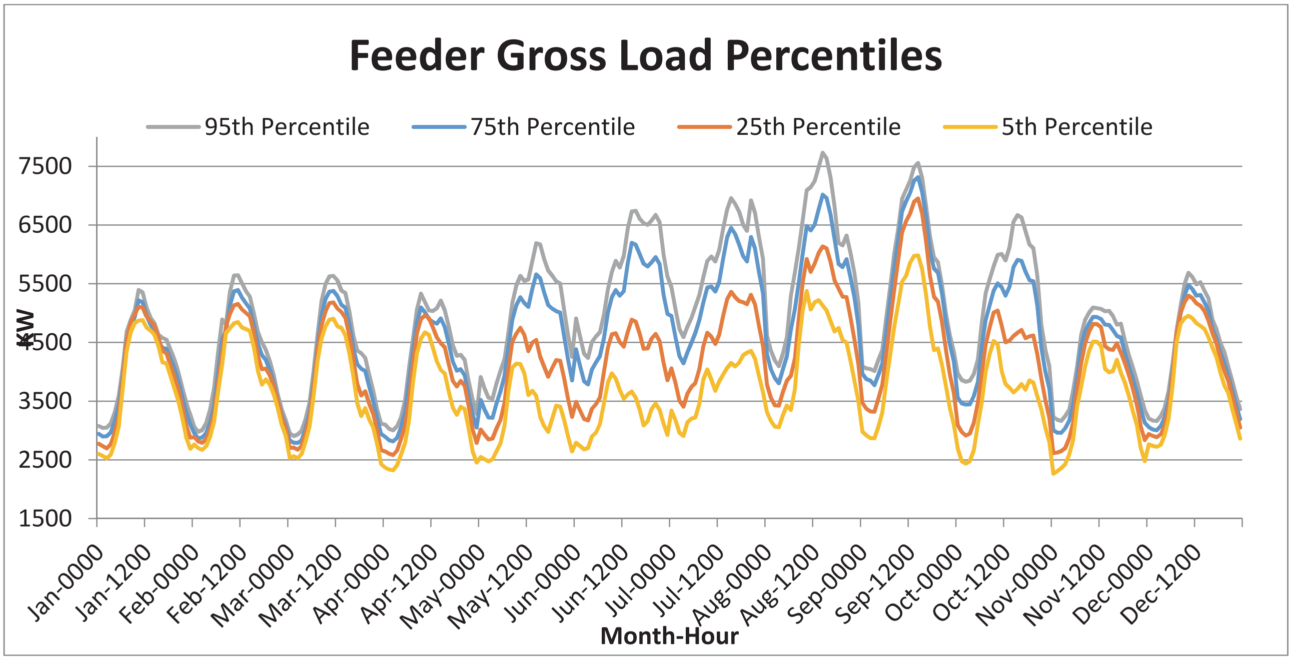

Figure 2: Load percentiles

For Demo B, PG&E used the 95th percentile shape to approximate the expected Month-Hour profile of future overloads during peaks periods.

DERs can also have percentile generation shapes based on local system conditions; a clear example is how cloud patterns have a direct impact on local solar generation.

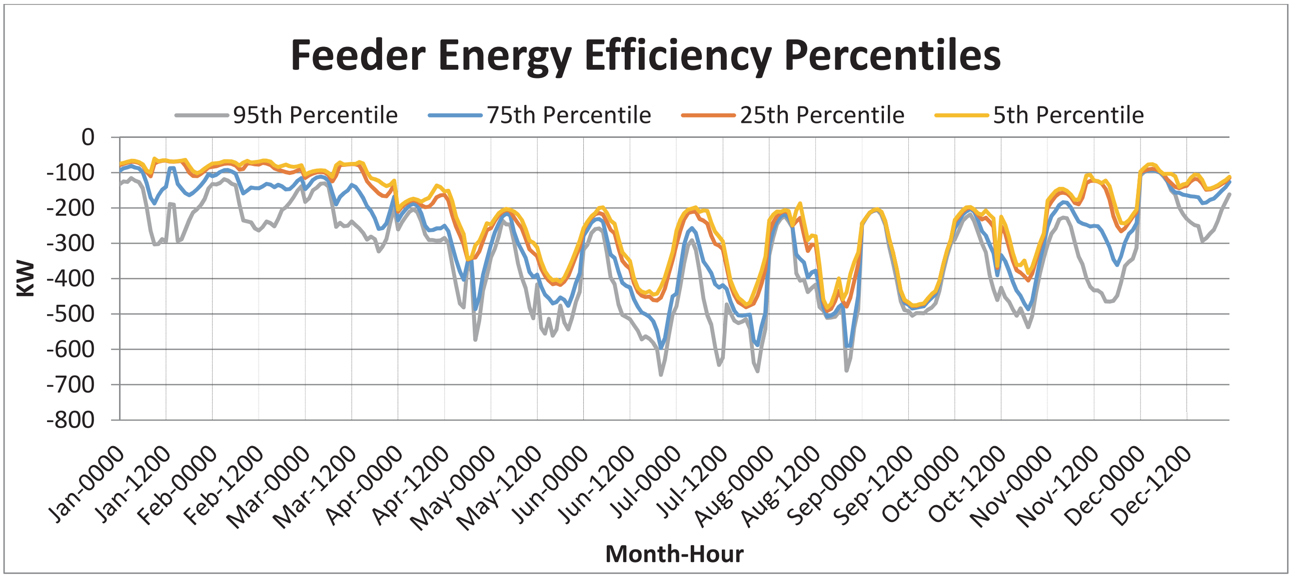

Figure 3: Generation percentiles

Using statistical models, IA has created software tools to model Month-Hour profiles for each DER type and gross load based on their 25th, 50th, 75th and 95th percentiles. For Demo B, PG&E used a typical profile for DG and EV and the 95th percentile for EE to calculate the coincident DER contribution during circuit peaks. Additional energy efficiency impact is expected when loads are also high.

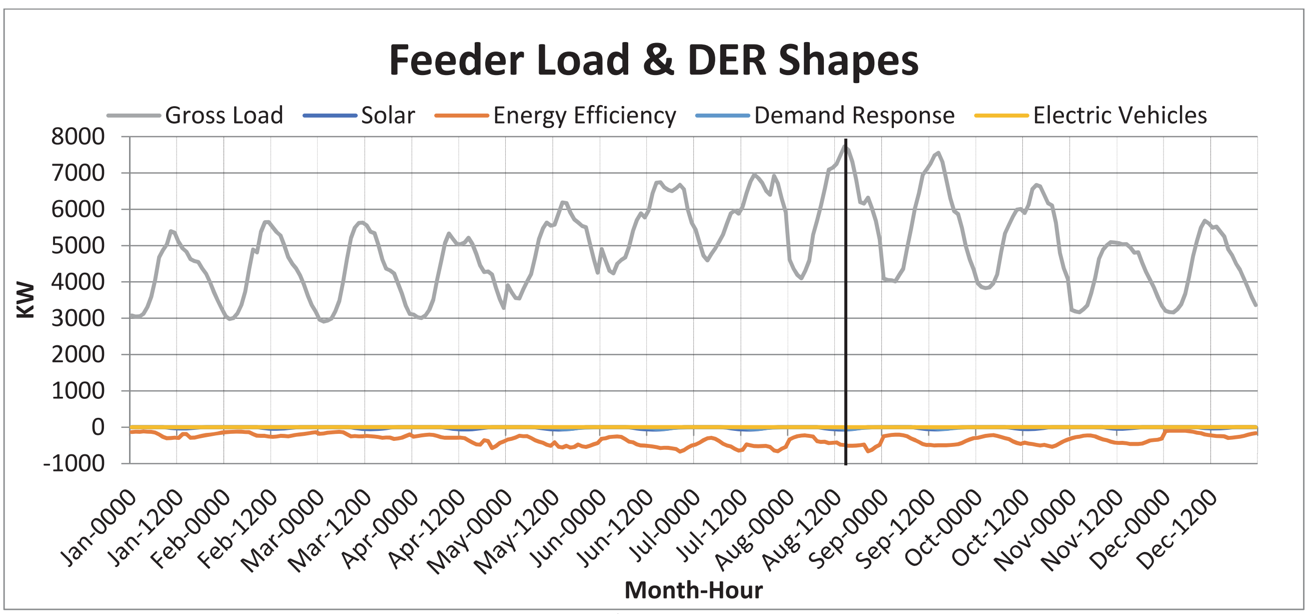

Figure 4: Load & DER 95th percentile with load peak

Currently, PG&E calculates the peak by finding the Month-Hour corresponding to the maximum gross load for each year to determine the coincident DER contribution. This peak usually depends on the customer composition (residential, commercial, agricultural, etc.) and the existing DERs on the system, which are embedded in the data used to develop the load shape profiles.

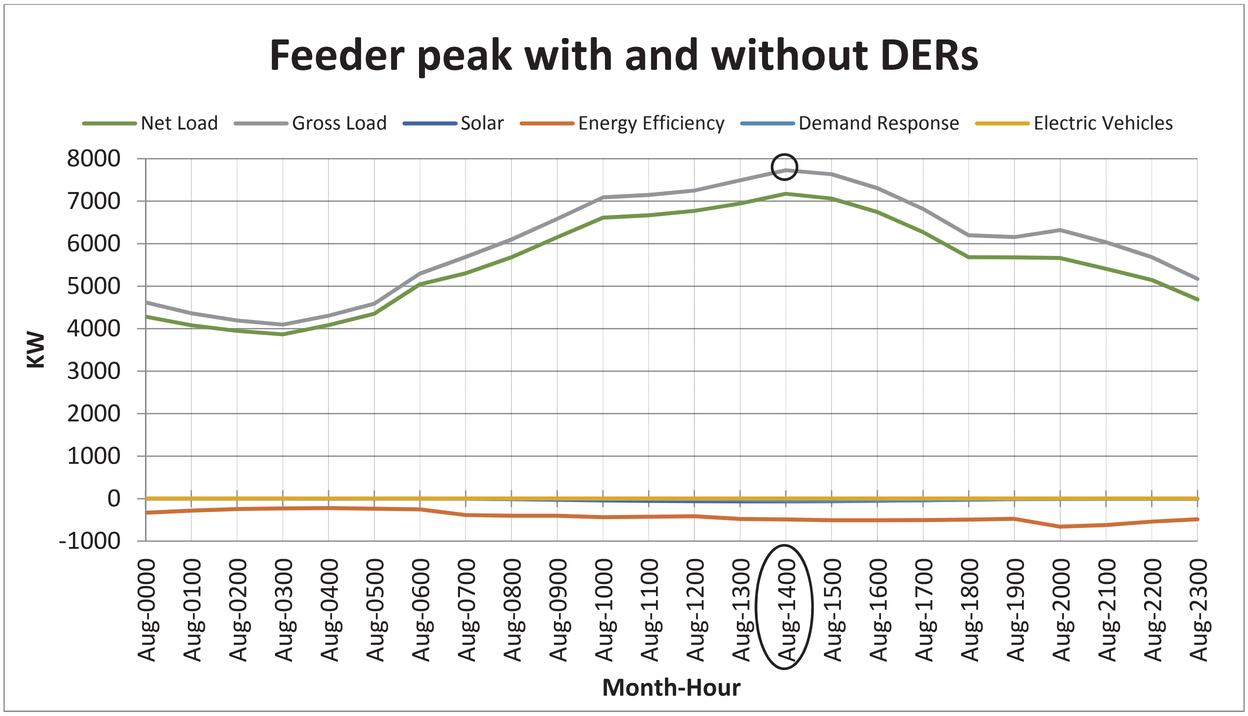

Figure 5: Gross and Net Load for each hour in August

The graph above shows, as an example, a modified feeder load shape after incorporating DERs at each coincident Month-Hour. We have calculated this Net Load by adding the 95th percentile of Gross Load and EE, and typical DG and EV hourly amounts. Demand Response (DR) was excluded from this calculation because it is only utilized during extreme emergency situations and doesn't determine the baseline load shape of the circuit.

The DER coincident peak provided in the Demo B heat map and downloadable dataset is calculated in steps listed below:

1. Find the maximum power consumption of the 95th percentile gross load in each year for each feeder

2. Determine the Month-Hour of that maximum to determine the peak timing
3. Calculate the DER contribution at the peak Month-Hour for that feeder (typical DG, EV and 95th percentile EE)
4. Determine the aggregated DER contribution by summing EE, EV and DG
5. Repeat for each feeder and each year (2017 – 2026)

12 Appendix 2: E3 LNBA Tool Documentation

The following link provides the Demo B LNBA Tool and associated documentation, both developed by E3 for the joint IOUs, PG&E, SCE and SDG&E: https://e3.sharefile.com/d-sb2965cf362c48399

13 Appendix 3: Table Mapping Requirements to Final Deliverables

Requirement	ACR Description	ACR	Document	Location in Document
DPA Selection/Projects for Deferral	In selecting which DPA to study, the IOUs were instructed to, at minimum, evaluate one near-term (0-3 year project lead time) and one longer-term (3 or more year lead time) distribution infrastructure project for possible deferral. This guidance ruling expands the scope of the Demonstration Project B to require demonstration of at least one voltage support/power quality- or reliability/resiliency-related deferral opportunity in addition to one or more capacity-related opportunities. Both types of opportunities may be located in the same DPA, but if the DPA selected by any IOU does not include noncapacity-related opportunities, the IOU must evaluate a noncapacity project in another DPA.	4.1; pg. A24	Final Report	Section 4
LNBA Methodology Requirements	The approach is to specify a primary analysis that the IOUs shall execute and a secondary analysis that the IOUs may execute in addition to the required analysis. Consistent with the Roadmap staff proposal, the primary analysis shall use DERAC values, if available, for system-level values. For the primary analysis, the IOUs are directed to develop certain system-level values that are not yet included in the DERAC (e.g., Flexible RA, renewables integration costs, etc.) to the extent feasible.	4.3; pg. A26-A28	Final Report; (See also LNBA Tool tab)	Ch. 8, 9, Appendix 2; (See LNBA Tool tab)
Table 2	Primary Analysis	4.3; pg. A27-A28	Final Report	Section 2.1.2
LNBA Specific Requirements				
Project Identification	The IOUs shall identify the full range of electric services that result in avoided costs for all locations within the DPAs selected for analysis. The values shall include any and all electrical services associated with distribution grid upgrades identified in (i) the utility distribution planning process, (ii) circuit reliability improvement process and (iii) maintenance process.	4.4.1 (1)(A); pg. A29	Final Report	Final Report - Ch. 5, 6, 7; Downloadable Dataset and Heat Map
List of Locations for Projects	Develop a list of locations where upgrade projects, circuit reliability, or maintenance projects may occur over each of the planning horizons to the extent possible	4.4.1 (1)(B) i; pg. A29	Final Report, Downloadable Dataset	Final Report - Ch. 5, 6, 7; Downloadable Dataset and Heat Map

Cost of Projects	Use existing approaches for estimating costs of required projects identified	4.4.1 (1)(B) ii; pg. A29	Final Report, Downlo adable Dataset	Section 8.2.1
Time Horizon of System Upgrade Needs	System upgrade needs identified in the processes should be in three categories that correspond to the near term forecast (1.5 – 3 year), intermediate term (3-5 year) and long term (5-10 year) or other time ranges, as appropriate and that correspond to current utility forecasting practice. A fourth category may be created employing "ultra-long-term forecast" greater than 10 years to the extent that such a time frame is supported in existing tools.	4.4.1 (1)(B) iii; pg. A29	Final Report, Downlo adable Dataset	Final Report - Ch. 5, 6, 7; Downloada ble Dataset and Heat Map
List of Electric Services from Projects	Prepare a location specific list of electric services associated with the planned distribution upgrades, and present these electric service needs in machine readable and map based formats.	4.4.1 (1)(B) iv; pg. A30	Downlo adable Dataset	Final Report - Ch. 5, 6, 7; Downloada ble Dataset and Heat Map
DER capabilities to provide Electric Services	For all electrical services identified, identify DER capabilities that would provide the electrical service. As a starting point, consider all DER derived from standard and 'smart' inverters and synchronous machines.	4.4.1 (1)(B) v; pg. A30	Final Report	Final Report - Ch. 5 and Downloada ble Dataset
Specifications of System Upgrade Needs	A description of the various needs underlying the distribution grid upgrades; Electrical parameters for each grid upgrade including total capacity increase, real and reactive power management and power quality requirements; An equipment list of components required to accomplish the capacity increase, maintenance action or reliability improvement; Project specifications for reliability, maintenance or capacity upgrade projects identified by the utilities shall include specifications of the following services as applicable: Voltage Control or Regulation, Reactive Supply, Frequency Regulation, Other Power Quality Services, Avoided Energy Losses, Equipment Life Extension, Improved SAIFI, SAIDI and MAIFI results	4.4.1 (1)(B) vi(a-d); pg. A30	Final Report, Downlo adable Dataset	Final Report - Ch. 5 and Downloada ble Dataset
Compute Avoided Cost	Compute a total avoided cost for each location within the DPA selected for analysis using the Real Economic Carrying Charge method to calculate the deferral value of these projects. Assign these costs to the four avoided cost categories in the DERAC calculator for this location. Use forecast horizons consistent with the time horizon above.	4.4.1 (1)(B) vii(a-c); pg. A31	Final Report; (See also LNBA Tool tab)	Final Report - Ch. 5 and 9 and(See LNBA Tool Tab)

Distribution System Services - Conservation Voltage Reduction and Volt/VAR optimization	To the extent that DER can provide distribution system services, the location of such needs and the specifications for providing them should be indicated on the LNBA maps. This analysis shall include opportunities for conservation voltage reduction and volt/VAR optimization. Additional services may be identified by the Working Group.	4.4.1 (1)(C) ; pg. A31	Final Report	Sections 3.2.2 and 9.3.1
Transmission CapEx and OpEx	For avoided costs related to transmission capital and operating expenditures, the IOUs shall, to the extent possible, quantify the co-benefit value of ensuring (through targeted, distribution-level DER sourcing) that preferred resources relied upon to meet planning requirements in the California ISO's 2015-16 transmission plan, Section 7.3, materialize as assumed in those locations. The IOUs shall provide work papers with a clear description of the methods and data used. If the IOUs are unable to quantify this value, they should use the avoided transmission values in the Net Energy Metering (NEM) Public Tool developed in R. 14-07-002.44	4.4.1 (2) + (A); pg. A31-A32	Final Report; (See also LNBA Tool tab)	8.3; (See also LNBA Tool tab)
Line Losses	For the secondary analysis, use the DERAC avoided capacity and energy values modified by avoided line losses may be based on the DER's specific location on a feeder and the time of day profile (not just an average distribution loss factor at the substation).45 The IOUs shall provide a clear description of the methods and data used.	4.4.1 (3); pg. A32	N/A	N/A, Demo B LNBA Methodology focuses on the Primary Analysis in Table 2 of the ACR only.
Fexible Generation	For the avoided cost of generation capacity for any DERs which provides flexible generation, the IOUs shall apply a method, such as the "F factor" which has been proposed for the Demand Response Cost-effectiveness Protocols.46 The IOUs shall provide work papers with a clear description of the methods and data used.	4.4.1 (4); pg. A32	Final Report	Sectio 9.4; Appendix 2
Avoided Energy - LMPs (Optional)	For the secondary analysis, the IOUs may also estimate the avoided cost of energy using locational marginal prices (LMPs) for a particular location, as per the method described in SCE's application. The IOUs shall provide work papers with a clear description of the methods and data used.	4.4.1 (5); pg. A32	N/A	N/A, Demo B LNBA Methodology focuses on the Primary Analysis in Table 2 of the ACR only.

Avoided Costs - Renewable Integration, Societal, and Public Safety	If values can be estimated or described related to the avoided costs of renewable integration, societal (e.g., environmental) impacts, or public safety impacts, the IOUs shall propose their methods for including these values or descriptions in the detailed implementation plans	4.4.1 (6); pg. A32-A33	Final Report; (See also LNBA Tool tab)	Final Report, Ch. 9; (See also LNBA Tool tab)
Methodology Description	The IOUs shall provide detailed descriptions of the method used, with a clear description of the modeling techniques or software used, as well as the sources and characteristics of the data used as inputs.	4.4.1 (7); pg. A33	Final Report	Final Report - Ch. 8, 9, Appendix 2
Software and Data Access	The IOUs shall provide access to any software and data used to stakeholders, within the limits of the CPUC's confidentiality provisions.	4.4.1 (8); pg. A33	Final Report, Downlo adable Dataset	Ch 8, LNBA Tool will be released, Heat Maps and dataset will be publicly available
DER Load Shapes and Adjustment Factors	Both the primary and secondary analyses should use the load shapes or adjustment factors appropriate to each specific DER.	4.4.1 (8); pg. A33	Final Report	Final Report - Ch. 4, Appendix 1
Other Related LNBA Requirements				
Heat Map	The IOU's LNBA results shall be made available via heat map, as a layer along with the ICA data in the online ICA map. The electric services at the project locations shall be displayed in the same map format as the ICA, or another more suitable format as determined in consultation with the working group. Total avoided cost estimates and other data may be also be required as determined in the data access portion of the proceeding.	4.4.2 (1); pg. A33	Final Report	Section 2.2.2, Appendix 1
DER Growth Scenarios	The IOUs shall execute and present their LNBA results under two DER growth scenarios: (a) the IEPR trajectory case, as filed in their applications (except that PG&E shall conform its PV forecast to the IEPR base case trajectory); and (b) the very high DER growth scenario, as filed in their applications. The DER growth scenario used in the distribution planning process for each forecast range should be made available in a heat map form as a layer in conjunction with the ICA layers identified earlier.	4.4.2 (2) + (a); pg. A33	Final Report	Throughou t
General Requirements				

Equipment Investment Deferral	The IOUs shall identify whether the following equipment investments can be deferred or avoided in these projects by DER: (a) voltage regulators, (b) load tap changers, (c) capacitors, (d) VAR compensators, (e) synchronous condensers, (f) automation of voltage regulation equipment, and (g) voltage instrumentation.	5.1 (C); pg. A34	Final Report, Downloadable Dataset	Final Report - Ch. 3, 5, 6, 7; Downloadable Dataset
Implementation Plan	The IOUs shall submit detailed implementation plans for project execution, including metrics, schedule and reporting interval. To the extent practicable, the IOUs shall consult with the LNBA working group on the development of the plan. The plan shall be submitted to the CPUC within 45 days of this ruling. The implementation plan shall include: A detailed description of the revised LNBA methodology; A description of the load forecasting or load characterization methodology or tool used to prepare the LNBA; A schedule/Gantt chart of the LNBA development process for each utility, showing: Any external (vendor or contract) work required to support it; Additional project details and milestones including, deliverables, issues to be tested, and tool configurations to be tested; Any additional resources required to implement Project B not described in the Applications	5.1 (d) + (i-iii); pg. A34-A35	Implementation Plan - Done	See IOU's Implementation Plans
Reporting	A plan for monitoring and reporting intermediate results and a schedule for reporting out. At a minimum, the Working Group shall report out at least two times over the course of the Demonstration B project: 1) an intermediate report; and 2) the final report.	5.1 (d)(iv); pg. A35	Implementation Plan - Done	See IOU's Implementation Plans

14 Appendix 4: O&M Project Details

14.1 Chico CPA O&M Projects for 2017:

Project Category	Area	Description	Year
Distribution Line O&M	Chico	Replace Recloser (Broken)	2017
Distribution Line O&M	Chico	Replace Insulator (Primary Squatter)	2017
Distribution Line O&M	Chico	Replace Insulator (Primary Squatter)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Replace Insulator (Primary Squatter)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Repair Pole (Broken/Damaged)	2017
Distribution Line O&M	Chico	Adjust Conductor (Sag/Clearance)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Replace Anchor (Soil/Eroded/Graded)	2017
Distribution Line O&M	Chico	Replace Anchor (Soil/Eroded/Graded)	2017
Distribution Line O&M	Chico	Replace Insulator (Broken/Damaged)	2017
Distribution Line O&M	Chico	Install Hardware/Framing (Missing)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Replace Anchor (Soil/Eroded/Graded)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Replace Anchor (Soil/Eroded/Graded)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Replace Anchor (Soil/Eroded/Graded)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017

Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Replace Insulator (Primary Squatter)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Replace Anchor (Soil/Eroded/Graded)	2017
Distribution Line O&M	Chico	Replace Anchor (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Anchor (Corroded)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Replace Insulator (Secondary Squatter)	2017
Distribution Line O&M	Chico	Replace Insulator (Primary Squatter)	2017
Distribution Line O&M	Chico	Replace Insulator (Primary Squatter)	2017
Distribution Line O&M	Chico	Replace Insulator (Primary Squatter)	2017
Distribution Line O&M	Chico	Replace Insulator (Primary Squatter)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Replace Insulator (Primary Squatter)	2017
Distribution Line O&M	Chico	Replace Anchor (Soil/Eroded/Graded)	2017
Distribution Line O&M	Chico	Replace Anchor (Soil/Eroded/Graded)	2017
Distribution Line O&M	Chico	Replace Anchor (Soil/Eroded/Graded)	2017
Distribution Line O&M	Chico	Replace Anchor (Soil/Eroded/Graded)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Adjust Conductor (Sag/Clearance)	2017
Distribution Line O&M	Chico	Remove Pole (Idle Facilities)	2017
Distribution Line O&M	Chico	Install Anchor (Missing)	2017
Distribution Line O&M	Chico	Replace Insulator (Primary Squatter)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Replace Insulator (Primary Squatter)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Replace Anchor (Soil/Eroded/Graded)	2017
Distribution Line O&M	Chico	Replace Anchor (Soil/Eroded/Graded)	2017
Distribution Line O&M	Chico	Replace Anchor (Soil/Eroded/Graded)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017

Distribution Line O&M	Chico	Adjust Conductor (Sag/Clearance)	2017
Distribution Line O&M	Chico	Replace Insulator (Primary Squatter)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Remove Pole (Idle Facilities)	2017
Distribution Line O&M	Chico	Adjust Conductor (Sag/Clearance)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Replace Molding (Broken/Damaged)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Replace Insulator (Primary Squatter)	2017
Distribution Line O&M	Chico	Adjust Pole (Leaning)	2017
Distribution Line O&M	Chico	Remove Pole (Idle Facilities)	2017
Distribution Line O&M	Chico	Replace Anchor (Soil/Eroded/Graded)	2017
Distribution Line O&M	Chico	Remove OH Facility (Idle Facilities)	2017
Distribution Line O&M	Chico	Remove OH Facility (Idle Facilities)	2017
Distribution Line O&M	Chico	Remove OH Facility (Idle Facilities)	2017
Distribution Line O&M	Chico	Remove OH Facility (Idle Facilities)	2017
Distribution Line O&M	Chico	Remove OH Facility (Idle Facilities)	2017
Distribution Line O&M	Chico	Remove Transformer (Idle Facilities)	2017
Distribution Line O&M	Chico	Remove Pole (Idle Facilities)	2017
Distribution Line O&M	Chico	Remove Conductor (Idle Facilities)	2017
Distribution Line O&M	Chico	Remove Conductor (Idle Facilities)	2017
Distribution Line O&M	Chico	Remove Pole (Idle Facilities)	2017
Distribution Line O&M	Chico	Remove OH Facility (Idle Facilities)	2017
Distribution Line O&M	Chico	Remove OH Facility (Idle Facilities)	2017
Distribution Line O&M	Chico	Remove OH Facility (Idle Facilities)	2017
Distribution Line O&M	Chico	Remove OH Facility (Idle Facilities)	2017
Distribution Line O&M	Chico	Remove OH Facility (Idle Facilities)	2017
Distribution Line O&M	Chico	Remove OH Facility (Idle Facilities)	2017
Distribution Line O&M	Chico	Remove OH Facility (Idle Facilities)	2017
Distribution Line O&M	Chico	Remove OH Facility (Idle Facilities)	2017
Distribution Line O&M	Chico	Remove OH Facility (Idle Facilities)	2017
Distribution Line O&M	Chico	Remove OH Facility (Idle Facilities)	2017
Distribution Line O&M	Chico	Remove OH Facility (Idle Facilities)	2017
Distribution Line O&M	Chico	Remove OH Facility (Idle Facilities)	2017
Distribution Line O&M	Chico	Remove Conductor (Idle Facilities)	2017
Distribution Line O&M	Chico	Replace Pole (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Crossarm (Broken/Damaged)	2017
Distribution Line O&M	Chico	Adjust Conductor (Clearance Impaired)	2017

Distribution Line O&M	Chico	Replace Crossarm (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Pole (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Crossarm (Decayed/Rotten)	2017
Distribution Line O&M	Chico	Replace Pole (Overloaded)	2017
Distribution Line O&M	Chico	Remove OH Facility (Idle Facilities)	2017
Distribution Line O&M	Chico	Replace Anchor (Broken/Damaged)	2017
Distribution Line O&M	Chico	Repair Conductor (Exposed)	2017
Distribution Line O&M	Chico	Replace Crossarm (Decayed/Rotten)	2017
Distribution Line O&M	Chico	Replace Insulator (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Pole (Broken/Damaged)	2017
Distribution Line O&M	Chico	Install CL Pole Tree/Vine (Decayed/Rotten)	2017
Distribution Line O&M	Chico	Replace Pole (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Pole (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Crossarm (Decayed/Rotten)	2017
Distribution Line O&M	Chico	Replace Pole (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Crossarm (Decayed/Rotten)	2017
Distribution Line O&M	Chico	Install Hardware/Framing (Missing)	2017
Distribution Line O&M	Chico	Replace Crossarm (Decayed/Rotten)	2017
Distribution Line O&M	Chico	Replace Anchor (Soil/Eroded/Graded)	2017
Distribution Line O&M	Chico	Repair Booster/Regulator (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Insulator (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Crossarm (Decayed/Rotten)	2017
Distribution Line O&M	Chico	Replace Insulator (Primary Squatter)	2017
Distribution Line O&M	Chico	Replace Pole (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Crossarm (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Pole (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Pole (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Crossarm (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Crossarm (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Crossarm (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Crossarm (Decayed/Rotten)	2017
Distribution Line O&M	Chico	Replace Crossarm (Decayed/Rotten)	2017
Distribution Line O&M	Chico	Replace Pole (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Pole (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Crossarm (Decayed/Rotten)	2017
Distribution Line O&M	Chico	Replace Pole (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Pole (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Crossarm (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Pole (Decayed/Rotten)	2017
Distribution Line O&M	Chico	Replace Pads (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Transformer - Padmount (Leaks/Seeps/Weeps)	2017

Distribution Line O&M	Chico	Replace Pads (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Crossarm (Decayed/Rotten)	2017
Distribution Line O&M	Chico	Replace Insulator (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Transformer (Leaks/Seeps/Weeps)	2017
Distribution Line O&M	Chico	Replace Crossarm (Decayed/Rotten)	2017
Distribution Line O&M	Chico	Replace Crossarm (Decayed/Rotten)	2017
Distribution Line O&M	Chico	Replace Pole (Burnt)	2017
Distribution Line O&M	Chico	Replace Pole (Burnt)	2017
Distribution Line O&M	Chico	Replace Crossarm (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Crossarm (Decayed/Rotten)	2017
Distribution Line O&M	Chico	Replace Anchor (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Crossarm (Decayed/Rotten)	2017
Distribution Line O&M	Chico	Replace Crossarm (Decayed/Rotten)	2017
Distribution Line O&M	Chico	Replace Pole (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Anchor (Corroded)	2017
Distribution Line O&M	Chico	Replace Crossarm (Decayed/Rotten)	2017
Distribution Line O&M	Chico	Replace Crossarm (Decayed/Rotten)	2017
Distribution Line O&M	Chico	Replace Insulator (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Crossarm (Decayed/Rotten)	2017
Distribution Line O&M	Chico	Replace Crossarm (Decayed/Rotten)	2017
Distribution Line O&M	Chico	Replace Crossarm (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Crossarm (Decayed/Rotten)	2017
Distribution Line O&M	Chico	Replace Elbow LB (Swollen/Ruptured)	2017
Distribution Line O&M	Chico	Replace Transformer - Sub-Surface (Leaks/Seeps/Weeps)	2017
Distribution Line O&M	Chico	Replace Switch (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Transformer - Padmount (Corroded)	2017
Distribution Line O&M	Chico	Replace Enclosure (Decayed/Rotten)	2017
Distribution Line O&M	Chico	Replace Enclosure (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Pads (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Pole (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Pole (Broken/Damaged)	2017
Distribution Line O&M	Chico	Remove Transformer (Idle Facilities)	2017
Distribution Line O&M	Chico	Replace Enclosure (Decayed/Rotten)	2017
Distribution Line O&M	Chico	Replace Enclosure (Broken/Damaged)	2017
Distribution Line O&M	Chico	Replace Cutout (Broken)	2017
Distribution Line O&M	Chico	Install OH Facility (Bird Prot Required)	2017
Distribution Line O&M	Chico	Install OH Facility (Bird Prot Required)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Trim Guy (Overgrown)	2017

Distribution Line O&M	Chico	Install Marking (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Repair Insulator (Primary Squatter)	2017
Distribution Line O&M	Chico	Repair Insulator (Primary Squatter)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Repair Insulator (Primary Squatter)	2017
Distribution Line O&M	Chico	Repair Ground (Exposed)	2017
Distribution Line O&M	Chico	Repair Insulator (Primary Squatter)	2017
Distribution Line O&M	Chico	Trim Tree/Vine (Overgrown)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Repair Insulator (Primary Squatter)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install Molding (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Repair Ground (Exposed)	2017
Distribution Line O&M	Chico	Repair Molding (Broken/Damaged)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Repair Insulator (Primary Squatter)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Trim Guy (Overgrown)	2017
Distribution Line O&M	Chico	Trim Guy (Overgrown)	2017
Distribution Line O&M	Chico	Remove Tree/Vine (Overgrown)	2017
Distribution Line O&M	Chico	Remove Tree/Vine (Overgrown)	2017
Distribution Line O&M	Chico	Repair Ground (Exposed)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017

Distribution Line O&M	Chico	Remove Tree/Vine (Overgrown)	2017
Distribution Line O&M	Chico	Remove Tree/Vine (Overgrown)	2017
Distribution Line O&M	Chico	Remove Tree/Vine (Overgrown)	2017
Distribution Line O&M	Chico	Remove Tree/Vine (Overgrown)	2017
Distribution Line O&M	Chico	Remove Tree/Vine (Overgrown)	2017
Distribution Line O&M	Chico	Repair Insulator (Secondary Squatter)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Replace Molding (Broken/Damaged)	2017
Distribution Line O&M	Chico	Repair Ground (Exposed)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Adjust Anchor (Soil/Eroded/Graded)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Repair Insulator (Primary Squatter)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Repair Insulator (Secondary Squatter)	2017
Distribution Line O&M	Chico	Repair Insulator (Primary Squatter)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install Marking (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017

Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Repair Pole (Broken/Damaged)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Trim Guy (Overgrown)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Adjust Guy (Loose)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Replace Molding (Broken/Damaged)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Trim Guy (Overgrown)	2017
Distribution Line O&M	Chico	Trim Guy (Overgrown)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Adjust Molding (Loose)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Repair Insulator (Primary Squatter)	2017
Distribution Line O&M	Chico	Repair Insulator (Primary Squatter)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Adjust Anchor (Soil/Eroded/Graded)	2017

Distribution Line O&M	Chico	Repair Insulator (Primary Squatter)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Adjust Anchor (Soil/Eroded/Graded)	2017
Distribution Line O&M	Chico	Repair Insulator (Primary Squatter)	2017
Distribution Line O&M	Chico	Remove Tree/Vine (Overgrown)	2017
Distribution Line O&M	Chico	Remove Tree/Vine (Overgrown)	2017
Distribution Line O&M	Chico	Repair Ground (Exposed)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Trim Guy (Overgrown)	2017
Distribution Line O&M	Chico	Trim Guy (Overgrown)	2017
Distribution Line O&M	Chico	Remove Tree/Vine (Overgrown)	2017
Distribution Line O&M	Chico	Remove Tree/Vine (Overgrown)	2017
Distribution Line O&M	Chico	Replace Molding (Broken/Damaged)	2017
Distribution Line O&M	Chico	Repair Insulator (Primary Squatter)	2017
Distribution Line O&M	Chico	Trim Tree/Vine (Overgrown)	2017
Distribution Line O&M	Chico	Trim Tree/Vine (Overgrown)	2017
Distribution Line O&M	Chico	Install Molding (Missing)	2017
Distribution Line O&M	Chico	Trim Guy (Overgrown)	2017
Distribution Line O&M	Chico	Trim Guy (Overgrown)	2017
Distribution Line O&M	Chico	Trim Guy (Overgrown)	2017
Distribution Line O&M	Chico	Trim Guy (Overgrown)	2017
Distribution Line O&M	Chico	Install Molding (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Repair Insulator (Primary Squatter)	2017
Distribution Line O&M	Chico	Trim Guy (Overgrown)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Repair Insulator (Primary Squatter)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Trim Tree/Vine (Overgrown)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Repair Anchor (Corroded)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Trim Guy (Overgrown)	2017
Distribution Line O&M	Chico	Repair Barrier Post (Broken/Damaged)	2017
Distribution Line O&M	Chico	Trim Guy (Overgrown)	2017

Distribution Line O&M	Chico	Trim Guy (Overgrown)	2017
Distribution Line O&M	Chico	Repair Ground (Exposed)	2017
Distribution Line O&M	Chico	Replace Enclosure (Broken/Damaged)	2017
Distribution Line O&M	Chico	Adjust Hardware/Framing (Loose)	2017
Distribution Line O&M	Chico	Install Retaining Wall (Missing)	2017
Distribution Line O&M	Chico	Replace Molding (Broken/Damaged)	2017
Distribution Line O&M	Chico	Trim Tree/Vine (Overgrown)	2017
Distribution Line O&M	Chico	Trim Tree/Vine (Overgrown)	2017
Distribution Line O&M	Chico	Trim Tree/Vine (Overgrown)	2017
Distribution Line O&M	Chico	Adjust Pads (Grade Problem)	2017
Distribution Line O&M	Chico	Install Retaining Wall (Missing)	2017
Distribution Line O&M	Chico	Remove Trees/Vines (Growing Into)	2017
Distribution Line O&M	Chico	Repair Ground (Exposed)	2017
Distribution Line O&M	Chico	Install Barrier Post (Missing)	2017
Distribution Line O&M	Chico	Repair Transformer - Padmount (Low Oil Level)	2017
Distribution Line O&M	Chico	Trim Tree/Vine (Overgrown)	2017
Distribution Line O&M	Chico	Trim Tree/Vine (Overgrown)	2017
Distribution Line O&M	Chico	Remove Tree/Vine (Overgrown)	2017
Distribution Line O&M	Chico	Repair Recloser/Sectionalizer (Broken/Damaged)	2017
Distribution Line O&M	Chico	Repair Transformer - Padmount (Broken/Damaged)	2017
Distribution Line O&M	Chico	Trim Tree/Vine (Overgrown)	2017
Distribution Line O&M	Chico	Adjust Pads (Grade Problem)	2017
Distribution Line O&M	Chico	Install Barrier Post (Missing)	2017
Distribution Line O&M	Chico	Adjust Hardware/Framing (Loose)	2017
Distribution Line O&M	Chico	Replace Molding (Broken/Damaged)	2017
Distribution Line O&M	Chico	Repair Crossarm (Broken/Damaged)	2017
Distribution Line O&M	Chico	Adjust Hardware/Framing (Loose)	2017
Distribution Line O&M	Chico	Trim Guy (Overgrown)	2017
Distribution Line O&M	Chico	Adjust Pads (Grade Problem)	2017
Distribution Line O&M	Chico	Trim Tree/Vine (Overgrown)	2017
Distribution Line O&M	Chico	Repair Crossarm (Decayed/Rotten)	2017
Distribution Line O&M	Chico	Trim Tree/Vine (Overgrown)	2017
Distribution Line O&M	Chico	Install Retaining Wall (Missing)	2017
Distribution Line O&M	Chico	Install Ground (Missing)	2017
Distribution Line O&M	Chico	Repair Pads (Broken/Damaged)	2017
Distribution Line O&M	Chico	Repair Pads (Broken/Damaged)	2017
Distribution Line O&M	Chico	Trim Tree/Vine (Clearance Impaired)	2017
Distribution Line O&M	Chico	Replace Connector (Temp Differential)	2017
Distribution Line O&M	Chico	Replace Connector (Temp Differential)	2017
Distribution Line O&M	Chico	Replace Connector (Temp Differential)	2017
Distribution Line O&M	Chico	Replace Connector (Temp Differential)	2017

Distribution Line O&M	Chico	Clean Enclosure (Full of Debris/Dirty)	2017
Distribution Line O&M	Chico	Replace Lid/Frame (Broken/Damaged)	2017
Distribution Line O&M	Chico	Repair Recloser/Sectionalizer (Broken/Damaged)	2017
Distribution Line O&M	Chico	Repair Recloser/Sectionalizer (Broken/Damaged)	2017
Distribution Line O&M	Chico	Adjust Conductor (Clearance Impaired)	2017
Distribution Line O&M	Chico	Repair Ground (Exposed)	2017
Distribution Line O&M	Chico	Install Guy Marker (Missing)	2017
Distribution Line O&M	Chico	Install Guy Marker (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Repair Ground (Exposed)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Repair Ground (Exposed)	2017
Distribution Line O&M	Chico	Repair Ground (Exposed)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Install High Sign (Missing)	2017
Distribution Line O&M	Chico	Adjust Molding (Loose)	2017

Distribution Line O&M	Chico	Clean Transformer - Padmount (Full of Debris/Dirty)	2017
Distribution Line O&M	Chico	Install Retaining Wall (Missing)	2017
Distribution Line O&M	Chico	Trim Trees/Vines (Growing Into)	2017
Distribution Line O&M	Chico	Trim Trees/Vines (Growing Into)	2017
Distribution Line O&M	Chico	Trim Trees/Vines (Growing Into)	2017
Distribution Line O&M	Chico	Trim Trees/Vines (Growing Into)	2017
Distribution Line O&M	Chico	Repair Ground (Exposed)	2017
Distribution Line O&M	Chico	Replace Transformer - Padmount (Broken/Damaged)	2017
Distribution Line O&M	Chico	Adjust Pads (Leaning)	2017
Distribution Line O&M	Chico	Adjust Pads (Leaning)	2017
Distribution Line O&M	Chico	Install Marking (Missing)	2017
Distribution Line O&M	Chico	Remove Trees/Vines (Growing Into)	2017
Distribution Line O&M	Chico	Remove Trees/Vines (Growing Into)	2017
Distribution Line O&M	Chico	Remove Trees/Vines (Growing Into)	2017
Distribution Line O&M	Chico	Clean UG Facility (Full of Debris/Dirty)	2017
Distribution Line O&M	Chico	Clean UG Facility (Full of Debris/Dirty)	2017
Distribution Line O&M	Chico	Clean UG Facility (Full of Debris/Dirty)	2017
Distribution Line O&M	Chico	Install Retaining Wall (Missing)	2017
Distribution Line O&M	Chico	Clean Lid/Frame (Full of Debris/Dirty)	2017
Distribution Line O&M	Chico	Clean Lid/Frame (Full of Debris/Dirty)	2017
Distribution Line O&M	Chico	Install Ground (Missing)	2017
Distribution Line O&M	Chico	Replace Pole (Decayed/Rotten)	2017
Distribution Substation O&M	Chico	Substation Asset Replacement (Emergency Replacement, Other)	2017
Distribution Substation O&M	Chico	ANITA SUB, CIRCUIT BREAKERS-Functional test	2017
Distribution Substation O&M	Chico	ANITA SUB, CIRCUIT BREAKERS-Functional test	2017
Distribution Substation O&M	Chico	ANITA SUB, CIRCUIT BREAKERS-Functional test	2017
Distribution Substation O&M	Chico	ANITA SUB, FACILITY-Fire Systems (SD) 12 MO	2017
Distribution Substation O&M	Chico	ANITA SUB, POWER TRANSFORMERS-TDA	2017
Distribution Substation O&M	Chico	ANITA SUB, POWER TRANSFORMERS-TDA	2017
Distribution Substation O&M	Chico	ANITA SUB, POWER TRANSFORMERS-TDA	2017
Distribution Substation O&M	Chico	ANITA SUB, POWER TRANSFORMERS-LTC thru neutral	2017
Distribution Substation O&M	Chico	ANITA SUB, POWER TRANSFORMERS-TASA	2017
Distribution Substation O&M	Chico	ANITA SUB, STATION BATTERIES-VLA Battery Resistance Test	2017

Distribution Substation O&M	Chico	ANITA SUB, STATION REGULATORS-TASA	2017
Distribution Substation O&M	Chico	ANITA SUB, STATION REGULATORS-LTC thru neutral	2017
Distribution Substation O&M	Chico	ANITA SUB, TABLE MOUNTAIN HQ-Infrared inspection	2017
Distribution Substation O&M	Chico	BUTTE SUB, CIRCUIT BREAKERS-Functional test	2017
Distribution Substation O&M	Chico	BUTTE SUB, CIRCUIT BREAKERS-Functional test	2017
Distribution Substation O&M	Chico	BUTTE SUB, CIRCUIT BREAKERS-Functional test	2017
Distribution Substation O&M	Chico	BUTTE SUB, CIRCUIT BREAKERS-Functional test	2017
Distribution Substation O&M	Chico	BUTTE SUB, CIRCUIT BREAKERS-Functional test	2017
Distribution Substation O&M	Chico	BUTTE SUB, CIRCUIT BREAKERS-Functional test	2017
Distribution Substation O&M	Chico	BUTTE SUB, POWER TRANSFORMERS-TDA	2017
Distribution Substation O&M	Chico	BUTTE SUB, POWER TRANSFORMERS-TDA	2017
Distribution Substation O&M	Chico	BUTTE SUB, POWER TRANSFORMERS-TDA	2017
Distribution Substation O&M	Chico	BUTTE SUB, POWER TRANSFORMERS-TASA	2017
Distribution Substation O&M	Chico	BUTTE SUB, POWER TRANSFORMERS-LTC thru neutral	2017
Distribution Substation O&M	Chico	BUTTE SUB, POWER TRANSFORMERS-TASA	2017
Distribution Substation O&M	Chico	BUTTE SUB, POWER TRANSFORMERS-LTC thru neutral	2017
Distribution Substation O&M	Chico	CHICO A SUB, CIRCUIT BREAKERS-Mechanism service	2017
Distribution Substation O&M	Chico	CHICO A SUB, CIRCUIT BREAKERS-Functional test	2017
Distribution Substation O&M	Chico	CHICO A SUB, POWER TRANSFORMERS-TDA	2017
Distribution Substation O&M	Chico	CHICO A SUB, STATION BATTERIES-VLA Battery Resistance Test	2017
Distribution Substation O&M	Chico	CHICO A SUB, STATION REGULATORS-TASA	2017
Distribution Substation O&M	Chico	CHICO A SUB, STATION REGULATORS-LTC thru neutral	2017
Distribution Substation O&M	Chico	CHICO A SUB, TABLE MOUNTAIN HQ-Infrared inspection	2017
Distribution	Chico	CHICO B SUB, CIRCUIT BREAKERS-Functional test	2017

Substation O&M			
Distribution Substation O&M	Chico	CHICO B SUB, CIRCUIT BREAKERS-Functional test	2017
Distribution Substation O&M	Chico	CHICO B SUB, POWER TRANSFORMERS-TASA	2017
Distribution Substation O&M	Chico	CHICO B SUB, POWER TRANSFORMERS-LTC thru neutral	2017
Distribution Substation O&M	Chico	CHICO B SUB, POWER TRANSFORMERS-TASA	2017
Distribution Substation O&M	Chico	CHICO B SUB, POWER TRANSFORMERS-LTC thru neutral	2017
Distribution Substation O&M	Chico	CHICO B SUB, STATION BATTERIES-VLA Battery Resistance Test	2017
Distribution Substation O&M	Chico	CHICO B SUB, TABLE MOUNTAIN HQ-Infrared inspection	2017
Distribution Substation O&M	Chico	CHICO C SUB, CIRCUIT BREAKERS-Breaker Exercise	2017
Distribution Substation O&M	Chico	CHICO C SUB, POWER TRANSFORMERS-TASA	2017
Distribution Substation O&M	Chico	CHICO C SUB, POWER TRANSFORMERS-LTC thru neutral	2017
Distribution Substation O&M	Chico	CHICO C SUB, TABLE MOUNTAIN HQ-Infrared inspection	2017
Distribution Substation O&M	Chico	DAYTON RD SUB, TABLE MOUNTAIN HQ-Infrared inspection	2017
Distribution Substation O&M	Chico	ESQUON SUB, CIRCUIT BREAKERS-Mechanism service	2017
Distribution Substation O&M	Chico	ESQUON SUB, POWER TRANSFORMERS-Spare xfmr tests	2017
Distribution Substation O&M	Chico	ESQUON SUB, POWER TRANSFORMERS-TDA	2017
Distribution Substation O&M	Chico	ESQUON SUB, STATION BATTERIES-VLA Battery Resistance Test	2017
Distribution Substation O&M	Chico	ESQUON SUB, STATION REGULATORS-TASA	2017
Distribution Substation O&M	Chico	ESQUON SUB, STATION REGULATORS-LTC thru neutral	2017
Distribution Substation O&M	Chico	ESQUON SUB, TABLE MOUNTAIN HQ-Infrared inspection	2017
Distribution Substation O&M	Chico	NORD SUB, CIRCUIT BREAKERS-Functional test	2017
Distribution Substation O&M	Chico	NORD SUB, CIRCUIT BREAKERS-Functional test	2017
Distribution Substation O&M	Chico	NORD SUB, POWER TRANSFORMERS-TDA	2017
Distribution Substation O&M	Chico	NORD SUB, POWER TRANSFORMERS-TASA	2017

Distribution Substation O&M	Chico	NORD SUB, POWER TRANSFORMERS-LTC thru neutral	2017
Distribution Substation O&M	Chico	NORD SUB, POWER TRANSFORMERS-TASA	2017
Distribution Substation O&M	Chico	NORD SUB, POWER TRANSFORMERS-LTC thru neutral	2017
Distribution Substation O&M	Chico	NORD SUB, STATION BATTERIES-VLA Battery Resistance Test	2017
Distribution Substation O&M	Chico	NORD SUB, TABLE MOUNTAIN HQ-Infrared inspection	2017
Distribution Substation O&M	Chico	NOTRE DAME SUB, CIRCUIT BREAKERS-Mechanism service	2017
Distribution Substation O&M	Chico	NOTRE DAME SUB, CIRCUIT BREAKERS-Functional test	2017
Distribution Substation O&M	Chico	NOTRE DAME SUB, CIRCUIT BREAKERS-Functional test	2017
Distribution Substation O&M	Chico	NOTRE DAME SUB, CIRCUIT BREAKERS-Mechanism service	2017
Distribution Substation O&M	Chico	NOTRE DAME SUB, CIRCUIT BREAKERS-Mechanism service	2017
Distribution Substation O&M	Chico	NOTRE DAME SUB, CIRCUIT BREAKERS-Functional test	2017
Distribution Substation O&M	Chico	NOTRE DAME SUB, CIRCUIT BREAKERS-Functional test	2017
Distribution Substation O&M	Chico	NOTRE DAME SUB, POWER TRANSFORMERS-TASA	2017
Distribution Substation O&M	Chico	NOTRE DAME SUB, POWER TRANSFORMERS-LTC thru neutral	2017
Distribution Substation O&M	Chico	NOTRE DAME SUB, STATION BATTERIES-NICAD INTERCELL BATTERY RESISTANCE TEST	2017
Distribution Substation O&M	Chico	NOTRE DAME SUB, TABLE MOUNTAIN HQ-Infrared inspection	2017
Distribution Substation O&M	Chico	SYCAMORE CREEK SUB, CIRCUIT BREAKERS-Functional test	2017
Distribution Substation O&M	Chico	SYCAMORE CREEK SUB, CIRCUIT BREAKERS-Functional test	2017
Distribution Substation O&M	Chico	SYCAMORE CREEK SUB, CIRCUIT BREAKERS-Functional test	2017
Distribution Substation O&M	Chico	SYCAMORE CREEK SUB, CIRCUIT BREAKERS-Functional test	2017
Distribution Substation O&M	Chico	SYCAMORE CREEK SUB, CIRCUIT BREAKERS-Functional test	2017
Distribution Substation O&M	Chico	SYCAMORE CREEK SUB, CIRCUIT BREAKERS-Mechanism service	2017
Distribution Substation O&M	Chico	SYCAMORE CREEK SUB, POWER TRANSFORMERS-TDA	2017
Distribution	Chico	SYCAMORE CREEK SUB, POWER TRANSFORMERS-TASA	2017

Substation O&M			
Distribution Substation O&M	Chico	SYCAMORE CREEK SUB, POWER TRANSFORMERS-LTC thru neutral	2017
Distribution Substation O&M	Chico	SYCAMORE CREEK SUB, POWER TRANSFORMERS-TASA	2017
Distribution Substation O&M	Chico	SYCAMORE CREEK SUB, POWER TRANSFORMERS-LTC thru neutral	2017
Distribution Substation O&M	Chico	SYCAMORE CREEK SUB, POWER TRANSFORMERS-TASA	2017
Distribution Substation O&M	Chico	SYCAMORE CREEK SUB, POWER TRANSFORMERS-LTC thru neutral	2017
Distribution Substation O&M	Chico	SYCAMORE CREEK SUB, STATION BATTERIES-VLA Battery Resistance Test	2017
Distribution Substation O&M	Chico	SYCAMORE CREEK SUB, TABLE MOUNTAIN HQ-Infrared inspection	2017
Transmission Substation O&M	Chico	ANITA SUB, CIRCUIT BREAKERS-Exercise	2017
Transmission Substation O&M	Chico	ANITA SUB, STATION BATTERIES-VLA Battery Resistance Test	2017
Transmission Substation O&M	Chico	BUTTE SUB, CIRCUIT BREAKERS-Exercise	2017
Transmission Substation O&M	Chico	BUTTE SUB, CIRCUIT BREAKERS-Exercise	2017
Transmission Substation O&M	Chico	BUTTE SUB, CIRCUIT BREAKERS-Exercise	2017
Transmission Substation O&M	Chico	BUTTE SUB, CIRCUIT BREAKERS-Exercise	2017
Transmission Substation O&M	Chico	BUTTE SUB, CIRCUIT BREAKERS-Exercise	2017
Transmission Substation O&M	Chico	BUTTE SUB, CIRCUIT BREAKERS-Exercise	2017
Transmission Substation O&M	Chico	BUTTE SUB, CIRCUIT BREAKERS-Exercise	2017
Transmission Substation O&M	Chico	BUTTE SUB, CIRCUIT BREAKERS-Exercise	2017
Transmission Substation O&M	Chico	BUTTE SUB, CIRCUIT BREAKERS-Exercise	2017
Transmission Substation O&M	Chico	BUTTE SUB, CIRCUIT BREAKERS-Exercise	2017
Transmission Substation O&M	Chico	BUTTE SUB, CIRCUIT BREAKERS-Exercise	2017
Transmission Substation O&M	Chico	BUTTE SUB, STATION BATTERIES-VLA Battery Resistance Test	2017
Transmission Substation O&M	Chico	BUTTE SUB, STATION REGULATORS-TASA	2017
Transmission Substation O&M	Chico	BUTTE SUB, TABLE MOUNTAIN HQ-Infrared inspection	2017

Transmission Substation O&M	Chico	CHICO A SUB, CIRCUIT BREAKERS-Exercise	2017
Transmission Substation O&M	Chico	CHICO A SUB, CIRCUIT BREAKERS-Exercise	2017
Transmission Substation O&M	Chico	CHICO A SUB, CIRCUIT BREAKERS-Exercise	2017
Transmission Substation O&M	Chico	NOTRE DAME SUB, CIRCUIT BREAKERS-Exercise	2017
Transmission Substation O&M	Chico	NOTRE DAME SUB, CIRCUIT BREAKERS-Exercise	2017
Transmission Substation O&M	Chico	NOTRE DAME SUB, CIRCUIT BREAKERS-Exercise	2017
Transmission Substation O&M	Chico	SYCAMORE CREEK SUB, CIRCUIT BREAKERS-Exercise	2017
Transmission Substation O&M	Chico	SYCAMORE CREEK SUB, CIRCUIT BREAKERS-Exercise	2017
Transmission Substation O&M	Chico	SYCAMORE CREEK SUB, CIRCUIT SWITCHERS-Mechanism service	2017
Transmission Substation O&M	Chico	SYCAMORE CREEK SUB, CIRCUIT SWITCHERS-Mechanism service	2017

14.2 Chowchilla DPA O&M Projects for 2017:

Project Category	Project Area	Description	Year
Distribution Line O&M	chowchilla	Replace Crossarm (Decayed/Rotten)	2017
Distribution Line O&M	chowchilla	Replace Anchor (Broken/Damaged)	2017
Distribution Line O&M	chowchilla	Replace Lightning Arrestor (Flashed)	2017
Distribution Line O&M	chowchilla	Replace Lightning Arrestor (Broken/Damaged)	2017
Distribution Line O&M	chowchilla	Replace Lightning Arrestor (Flashed)	2017
Distribution Line O&M	chowchilla	Replace Elbow LB (Swollen/Ruptured)	2017
Distribution Line O&M	chowchilla	Replace Pole (Decayed/Rotten)	2017
Distribution Line O&M	chowchilla	Replace Capacitor (Broken)	2017
Distribution Line O&M	chowchilla	Repair Recloser (Broken)	2017
Distribution Line O&M	chowchilla	Replace Cutout (Broken)	2017
Distribution Line O&M	chowchilla	Replace Regulator (Broken)	2017
Distribution Line O&M	chowchilla	Repair Recloser (Broken)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Replace Guy (Broken/Damaged)	2017

Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Replace Guy (Broken/Damaged)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Repair Guy (Broken/Damaged)	2017
Distribution Line O&M	chowchilla	Repair Guy (Broken/Damaged)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Trim Guy (Overgrown)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Repair Ground (Exposed)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Repair Ground (Exposed)	2017
Distribution Line O&M	chowchilla	Replace Molding (Broken/Damaged)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017

Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Replace Lid/Frame (Broken/Damaged)	2017
Distribution Line O&M	chowchilla	Repair Pads (Broken/Damaged)	2017
Distribution Line O&M	chowchilla	Replace Connector (Temp Differential)	2017
Distribution Line O&M	chowchilla	Repair Ground (Exposed)	2017
Distribution Line O&M	chowchilla	Repair Ground (Exposed)	2017
Distribution Line O&M	chowchilla	Repair Ground (Exposed)	2017
Distribution Line O&M	chowchilla	Repair Ground (Exposed)	2017
Distribution Line O&M	chowchilla	Repair Ground (Exposed)	2017
Distribution Line O&M	chowchilla	Install Marking (Missing)	2017
Distribution Line O&M	chowchilla	Repair Ground (Exposed)	2017
Distribution Line O&M	chowchilla	Repair Ground (Exposed)	2017
Distribution Line O&M	chowchilla	Install Marking (Missing)	2017
Distribution Line O&M	chowchilla	Repair Ground (Exposed)	2017
Distribution Line O&M	chowchilla	Repair Ground (Exposed)	2017
Distribution Line O&M	chowchilla	Repair Ground (Exposed)	2017
Distribution Line O&M	chowchilla	Repair Ground (Exposed)	2017
Distribution Line O&M	chowchilla	Repair Ground (Exposed)	2017
Distribution Line O&M	chowchilla	Repair Ground (Exposed)	2017
Distribution Line O&M	chowchilla	Repair Ground (Exposed)	2017
Distribution Line O&M	chowchilla	Repair Ground (Exposed)	2017
Distribution Line O&M	chowchilla	Repair Ground (Exposed)	2017
Distribution Line O&M	chowchilla	Repair Ground (Exposed)	2017
Distribution Line O&M	chowchilla	Repair Ground (Exposed)	2017
Distribution Line O&M	chowchilla	Replace Lid/Frame (Corroded)	2017
Distribution Line O&M	chowchilla	Replace Lid/Frame (Corroded)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Line O&M	chowchilla	Install High Sign (Missing)	2017
Distribution Substation O&M	Chowchilla	Substation Asset Replacement (Replace Other Equipment, Animal Abatement)	2017
Distribution Substation O&M	Chowchilla	CHOWCHILLA SUB, MERCED HQ-Infrared inspection	2017
Distribution Substation O&M	Chowchilla	CHOWCHILLA SUB, POWER TRANSFORMERS-TASA	2017
Distribution Substation O&M	Chowchilla	CHOWCHILLA SUB, POWER TRANSFORMERS-LTC thru neutral	2017
Distribution Substation O&M	Chowchilla	CHOWCHILLA SUB, POWER TRANSFORMERS-TASA	2017

Distribution Substation O&M	Chowchilla	CHOWCHILLA SUB, STATION BATTERIES-VLA Battery Resistance Test	2017
Distribution Substation O&M	Chowchilla	DAIRYLAND SUB, MERCED HQ-Infrared inspection	2017
Distribution Substation O&M	Chowchilla	DAIRYLAND SUB, POWER TRANSFORMERS-TASA	2017
Distribution Substation O&M	Chowchilla	DAIRYLAND SUB, POWER TRANSFORMERS-TASA	2017
Distribution Substation O&M	Chowchilla	DAIRYLAND SUB, STATION BATTERIES-VLA Battery Resistance Test	2017
Distribution Substation O&M	Chowchilla	EL NIDO SUB, CIRCUIT BREAKERS-Exercise	2017
Distribution Substation O&M	Chowchilla	EL NIDO SUB, CIRCUIT BREAKERS-Functional test	2017
Distribution Substation O&M	Chowchilla	EL NIDO SUB, MERCED HQ-Infrared inspection	2017
Distribution Substation O&M	Chowchilla	EL NIDO SUB, POWER TRANSFORMERS-TDA	2017
Distribution Substation O&M	Chowchilla	EL NIDO SUB, POWER TRANSFORMERS-TASA	2017
Distribution Substation O&M	Chowchilla	EL NIDO SUB, POWER TRANSFORMERS-LTC thru neutral	2017
Distribution Substation O&M	Chowchilla	EL NIDO SUB, POWER TRANSFORMERS-TASA	2017
Distribution Substation O&M	Chowchilla	EL NIDO SUB, POWER TRANSFORMERS-LTC thru neutral	2017
Distribution Substation O&M	Chowchilla	EL NIDO SUB, STATION BATTERIES-VLA Battery Resistance Test	2017
Distribution Substation O&M	Chowchilla	LE GRAND SUB, CIRCUIT BREAKERS-Exercise	2017
Distribution Substation O&M	Chowchilla	LE GRAND SUB, CIRCUIT BREAKERS-Mechanism service	2017
Distribution Substation O&M	Chowchilla	LE GRAND SUB, CIRCUIT BREAKERS-Functional test	2017
Distribution Substation O&M	Chowchilla	LE GRAND SUB, MERCED HQ-Infrared inspection	2017
Distribution Substation O&M	Chowchilla	LE GRAND SUB, STATION BATTERIES-VLA Battery Resistance Test	2017
Distribution Substation O&M	Chowchilla	LE GRAND SUB, STATION REGULATORS-TASA	2017
Distribution Substation O&M	Chowchilla	LE GRAND SUB, STATION REGULATORS-LTC thru neutral	2017
Transmission Substation O&M	Chowchilla	CHOWCHILLA SUB, CIRCUIT BREAKERS-Exercise	2017
Transmission Substation O&M	Chowchilla	CHOWCHILLA SUB, CIRCUIT BREAKERS-Exercise	2017
Transmission Substation O&M	Chowchilla	CHOWCHILLA SUB, CIRCUIT SWITCHERS-Mechanism service	2017
Transmission Substation O&M	Chowchilla	DAIRYLAND SUB, CIRCUIT BREAKERS-Exercise	2017
Transmission Substation O&M	Chowchilla	DAIRYLAND SUB, CIRCUIT BREAKERS-Exercise	2017
Transmission Substation O&M	Chowchilla	DAIRYLAND SUB, CIRCUIT BREAKERS-Exercise	2017
Transmission Substation O&M	Chowchilla	LE GRAND SUB, CIRCUIT BREAKERS-Exercise	2017

Transmission Substation O&M	Chowchilla	LE GRAND SUB, CIRCUIT BREAKERS-Exercise	2017
Transmission Substation O&M	Chowchilla	LE GRAND SUB, CIRCUIT BREAKERS-Exercise	2017
Transmission Substation O&M	Chowchilla	LE GRAND SUB, CIRCUIT BREAKERS-Exercise	2017